North American Electric Reliability Council

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MAPP
Mid-continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed by the electric utility industry in 1968 to promote the RELIABILITY of bulk power supply in the electric utility systems of North America. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the power systems in the United States and Canada.

RELIABILITY, in a bulk power electric system, is the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service.

Bulk power electric system reliability can be addressed by considering two basic and functional aspects of the bulk power system—adequacy and security.

ADEQUACY is the ability of the bulk power electric system to supply the aggregate electrical power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk power electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

Copyright © 1985 by North American Electric Reliability Council. All rights reserved.

48630-3-F

1985 Reliability Review

A REVIEW OF BULK POWER SYSTEM RELIABILITY IN NORTH AMERICA

TABLE OF CONTENTS

EXECUTIVE SUMMARY 2

FOREWORD 6

PEAK DEMAND AND ENERGY 8

GENERATING CAPACITY AND FUEL 11

ASSESSMENT OF POWER SUPPLY ADEQUACY 17

TRANSMISSION ISSUES 19

OPERATIONS 24

REGIONAL ASSESSMENTS OF RELIABILITY 26

EXECUTIVE SUMMARY

THE OUTLOOK

The North American Electric Reliability Council expects the reliability of electric supplies to decline over the next ten years. By the mid-1990's, electric generating capacity margins will be near minimum acceptable levels in some parts of the United States, even if electricity demands grow no faster than the present forecast rate of 2.2% per year. In Canada, generating capacity is judged to be adequate for the entire 1985-1994 period.

Some of the generating capacity that will be needed ten years from now has not yet been committed to by utilities. Actual commitments for major generating units in the United States have virtually stopped. Unless lead times can be substantially shortened, this uncommitted capacity may not be in service when needed. Thus, the industry is in a precarious position to react to a growth in demand higher than presently forecast. Cogeneration, renewables, demand management and conservation will each play a role, but will account for only a fraction of the forecast need.

The future availability and performance of the electric utility industry's aging equipment is an additional unquantifiable factor. The composite age of our fossil-fueled steam electric generating capacity is 17 years and, in 1995, will be 25 years. Even with the addition of all planned units over the next 10 years, the utility industry will be entering 1995 with more than 100,000 MW of fossil-fueled steam capacity that is over 30 years old.

The prediction of future energy needs is uncertain at best. However, even if needs were precisely known, utilities would still be reluctant to commit to large power projects because of the large financial risks. Consequently, electric utilities appear to be adopting a "minimum capital outlay" policy. This will result in the least near-term cost to the customer and seems consistent with most regulatory mandates. However, the alternate with the least near-term cost may not be the least expensive in the long run. Such deferred costs may be a difficult future problem.

Electric transmission systems will continue to be loaded heavily with economy energy transfers. These transfers, from areas with low generation costs to areas with higher generation costs, help lower the cost of electricity to the customer but also lower the reliability of the electric power systems. When electric transmission systems are loaded to their maximum safe limits continuously, little margin remains to handle the unexpected. As a result, reliability suffers. Building additional transmission would help, but impediments exist which impede this partial remedy.

Interruptions to customer service in the future will test customers' acceptance of the risks now being taken by some utilities. The Electric Reliability Council is concerned that if our regulatory, economic, and national security policies do not reflect an increased awareness of the need for adequate future electric supplies, the specter of unreliable electric service may become reality.

FUTURE DEMAND GROWTH REMAINS UNCERTAIN

Long-term electricity growth forecasts continue to be uncertain. Electric utility forecasters, after witnessing many years of over 7% per year

electricity demand growth, did not anticipate the dramatic shift in electricity use following the price increases caused by the 1973-74 oil embargo. Ten-year forecasts of peak demand and electric energy growth have since been successively lowered with the present forecasts remaining essentially the same as last year's.

Whether utilities can satisfy future needs will depend on their ability to respond to changes in peak demand and energy requirements. While the general economy has been strong in the last two years and demands have exceeded forecasts, tenth-year forecasts by the utilities have remained about the same. The United States' utilities are forecasting 2.2% annual growth in summer peak demand and 2.4% in electric energy. In Canada, winter peak demand is expected to grow at 3.0% per year and energy at 3.1%.

Some key questions facing the industry are:

- Will the economies of Canada and the United States remain strong?
- How will the price of electricity move in relation to other fuels and the spendable income of customers?
- Will load management programs be effective?
- To what degree will customers develop their own electrical generation to offset their utility purchases?

LOAD MANAGEMENT

Utilities are relying on load management and conservation programs to restrain load growth. Some of our experts assert that their forecasts have been adjusted by up to 3% per year by these programs. There are practical limits to what load management and conservation programs can achieve; they will not eliminate the need for future generating capacity additions. Also, there is uncertainty as to whether these programs will continue to be supported by regulatory commissions and the public — and uncertainty as to the reliability of these programs once they are operational.

ELECTRICITY PRICES

Strong correlations have been demonstrated between electricity use and electricity price. Utilities which are completing large nuclear or coal construction programs will be seeking rate increases to recover the investment, which may in turn reduce the rate of load growth in these areas. The utility industry, however, is responding to forces of competition and has placed a major priority on controlling prices. Competition is coming from neighboring utilities, other fuels and customer-owned generating resources. As prices are expected to rise in some areas and fall in others, the effect on long-term demand and energy forecasts becomes more uncertain.

UTILITY PLANS FOR NEW CAPACITY TAKE A "WAIT AND SEE" APPROACH

Electricity is unique among energy sources in that it must be produced at the precise moment it is required; it cannot be produced in excess at times of low demand and saved for use at times of peak demand. Thus, the capability to produce electricity must be in place when the need for it arises. A reliable supply of electricity is vital to the health and well-being of a modern economy — when demands cannot be served, industry, commerce and citizens' lifestyles suffer.

EXECUTIVE SUMMARY

Given the uncertainty of future electric requirements and the critical nature of an adequate electric supply, it is important that utilities have the flexibility to respond to changing trends in future demand.

Utilities' plans for adding new capacity are about the same as they were last year. Several observations can be made about these plans.

- In the past year, there have been no new orders for large coal or nuclear units by United States utilities, and only one large coal unit was placed under construction.
- The program of building hydroelectric and nuclear generating plants in Canada is proceeding, which will make more energy available to utilities in the United States.
- During 1984, 8 nuclear units were canceled in the United States and 29 others were delayed; 24 coal units were also delayed an average of 20 months.
- Only 7 of the 16 nuclear units scheduled for 1984 operation in the United States were placed in service.
- Cogeneration and renewable resources are beginning to appear as significant components of utility generating expansion plans in Texas, California and New England.
- Smaller units with short lead times are gaining popularity as a planning option with utilities.

Overall, utilities are striving to maintain flexibility while avoiding long-term commitments. There is a willingness to take the risk that increases in load growth will not outstrip the ability to build or buy capacity.

TRANSMISSION ISSUES

The transmission systems continue to be heavily loaded with economy energy transfers a high percentage of the time. As a result, there is a greater vulnerability to system disturbances and customer service interruptions. Building more transmission lines would increase the capability to transfer economy energy and, at the same time, increase the capability to respond to emergencies. However, there are impediments and disincentives to planning, licensing and constructing new lines.

Since reliability has been exceedingly high in most regions since World War II, the constant supply of electricity has been taken for granted by the public and government officials. The Electric Reliability Council is concerned that this attitude, reflected in regulatory, economic and investment policy, will result in a gradual decline in reliability not easily nor quickly reversed.

THE UTILITIES' VIEW OF RESOURCE PLANNING AND RELIABILITY

The current theme for resource planning is "avoid commitments to large power projects." Almost all the utilities now facing severe financial crises

are in that situation because they have a large nuclear or coal unit under construction. Many such plants were planned to meet expected loads that have not yet materialized. Most utilities in good financial condition achieved that status by avoiding such projects or completing them several years ago. The lessons are plain to see. Thus, with some exceptions, financially healthy and ailing utilities alike are implementing a low capital, flexible strategy of resource planning as follows:

1. Maximize availability and utilization of existing resources.

2. Purchase power from other utilities, cogenerators and small power producers.

3. Implement load management and conservation programs.

4. Install small, short lead time generating units.

For some utilities, these steps could be insufficient to avoid occasional capacity shortages. For those utilities, provisions for interrupting and restoring loads will be needed.

In pursuing a philosophy such as this, which avoids major capital commitments, utilities believe they are following public mandate. Customers on the North American continent, while concerned with the cost of electricity, are presently unaware of the effect that an unreliable electric supply would have on them.

The Electric Reliability Council is concerned that continued implementation of this philosophy will lead to unreliable electric service in the 1990's, which the public will then find unacceptable.

FOREWORD

ABOUT THE COUNCIL

The North American Electric Reliability Council was formed by the electric utility industry in 1968 to promote the RELIABILITY of bulk power supply in the electric utility systems in North America. The Council consists of nine Regional Reliability Councils and one Affiliate encompassing virtually all the power systems in the United States and Canada, and the portion of the Mexican system (CFE) interconnected with California.

The governing body of the Council is its Board of Trustees, consisting of two representatives from each Regional Council, plus such additional representatives as prescribed in the By-Laws. There must always be at least one representative on the Board from a Canadian utility system and at least two utility representatives from each segment of the electric utility industry: Investor-owned, Federal, Rural Electric Cooperative, and State/Municipal.

Meetings of the Board are attended by observers from the United States Department of Energy, United States Federal Energy Regulatory Commission, Canadian National Energy Board, Edison Electric Institute, American Public Power Association and National Rural Electric Cooperative Association.

ABOUT THIS REPORT

In October, 1970, the North American Electric Reliability Council's Board of Trustees created the Interregional Review Subcommittee to review, on a continuing basis, the overall reliability of the North American bulk power systems as existing and planned among and within the Regional Reliability Councils.

This 1985 Review presents:

- The Subcommittee's assessment of future reliability.
- Discussion of the key factors and issues affecting the future of electric power supply, and
- Detailed region-by-region assessments of reliability, including discussion of those issues of specific regional concern.

In preparing this report, the Subcommittee interviewed representatives of selected regions, reviewed detailed self-assessments prepared by each of the nine Regional Reliability Councils, appraised utility plans and commitments for future bulk power system facilities, and assessed the potential effect of legislation, regulations and governmental policies on future reliability. This report is the culmination of these efforts and reflects the expertise, judgment, and interpretations of the Subcommittee members. The conclusions found in the report are based on current demand and capability projections and on the individual Regional assessments.

Unless otherwise noted, the data presented in the graphs and tables in this report have been submitted by the Regional Reliability Councils and reflect conditions as of January 1, 1985. Some data have been extracted from the April 1, 1985 Coordinated Bulk Power Supply Program (IE-411) Reports submitted to the United States Department of Energy by each Regional Reliability Council and other data from submittals made directly to the Electric Reliability Council. Detailed data and information on projected peak demand, energy requirements, generating capability and fossil fuel requirements are presented in a companion report by the North American Electric Reliability Council — "Electric Power Supply and Demand, 1985-1994."

PEAK DEMAND AND ENERGY

Long-term electric peak demand and energy forecasts remain essentially the same as projected last year for the United States and are slightly higher for Canada. Higher demands were experienced in 1984 than forecast, and electricity use during the first half of 1985 is running ahead of last year. However, conflicting indicators from the economic recovery, load management and conservation programs and short-term weather effects have clouded long-term trends. Utilities do not expect the recently experienced strong growth to persist throughout the 10-year period.

CURRENT EXPERIENCE

In 1984, electricity use again surprised most forecasters. Spurred by a longer and stronger than expected economic recovery, annual electric energy use increased by 4.4% over 1983 and 2.3% over what had been forecast. All regions showed increases over 1983 and all but MAPP exceeded their energy use forecast for 1984. Peak demands, both summer and winter, also showed increases over both 1983 actual and 1984 forecasts in most regions. Similar results were experienced in Canada where the economy was strengthening in 1984. A summary of the 1984 actual peak demand and energy experience is shown in Table 1.

A strengthening economy is reflected in the use of electricity. Although the growth rate of electricity consumption has moderated in recent months, the 12-month record of electric energy requirements (Figure 1) continues to show an increase. For the 12 months ending February 28, 1985, net energy for load in the United States was 3.5% above the comparable period one year ago, and 6.0% above for Canada.[1]

TEN-YEAR PROJECTIONS

Long-term electric peak demand and energy forecasts remain essentially the same as projected last year for the United States and are slightly higher for Canada. The electric utilities in the United States are projecting peak demand and energy to grow over the next 10 years at somewhat lower rates than projected last year. But, applying these lower rates of growth to the higher projections for 1985 result in the expected 1993 summer peak demand in the United States being essentially the same as last year's projection. Three of the regions (ECAR, NPCC, and WSCC) show a slightly higher projected 1993 summer peak demand in the United States than was shown last year. This year's peak demand and energy projections are shown in Table 2, and comparisons of last year's and this year's forecast growth rates are shown in Table 3.

[1]Although Nova Scotia became a member of NPCC in January, 1985, the data listed or shown pictorially in this report do not include information from that system.

Table 1 1984 Actual Peak Demand and Energy (in percent)

	United States	Canada
SUMMER PEAK DEMAND		
Increase over 1983 Actual	0.8	3.1
Increase over Forecast for 1984	1.0	1.0
WINTER PEAK DEMAND		
Increase over 1983/84 Actual	6.2	5.4
Increase over Forecast for 1984/85	6.6	3.6
ANNUAL ENERGY		
Increase over 1983 Actual	4.4	6.0
Increase over Forecast for 1984	2.3	2.0

Table 2 Forecast Peak Demand and Energy

	United States	Canada
SUMMER PEAK DEMAND (Thousands of MW)		
1985	465.1	43.8
1994	566.8	57.0
WINTER PEAK DEMAND (Thousands of MW)		
1985	422.9	60.8
1994	519.1	79.2
ANNUAL ENERGY (Millions of MWh)		
1985	2,499.4	328.6
1994	3,080.6	432.8

The forecast winter peak demand growth rates for Canada have also been lowered. However, an increased projection for 1985, coupled with the projected growth rate, results in an increase in the 1993 peak demand of about 2% over last year's projection for that year. Where this will lead in the longer term is still uncertain. However, the decreased peak demand and energy forecast in the United States shows that utilities are expecting that current upward trends will not persist through the 10-year period.

Utilities are relying on load management and conservation programs to restrain load growth. There are practical limits to what load management and conservation programs can achieve; they will defer, but not eliminate the need for future generating capacity additions. Also, there is uncertainty as to whether the programs will continue to be supported by regulatory commissions and the public.

Table 3 Forecast Average Annual Growth Rates of Peak Demand and Energy - %/yr.

	United States	Canada
SUMMER PEAK DEMAND		
This Year (1985-1994)	**2.2**	**3.0**
Last Year (1984-1993)	2.5	3.0
WINTER PEAK DEMAND		
This Year (1985-1994)	**2.3**	**3.0**
Last Year (1984-1993)	2.5	3.2
ANNUAL ENERGY		
This Year (1985-1994)	**2.4**	**3.1**
Last Year (1984-1993)	2.7	3.1

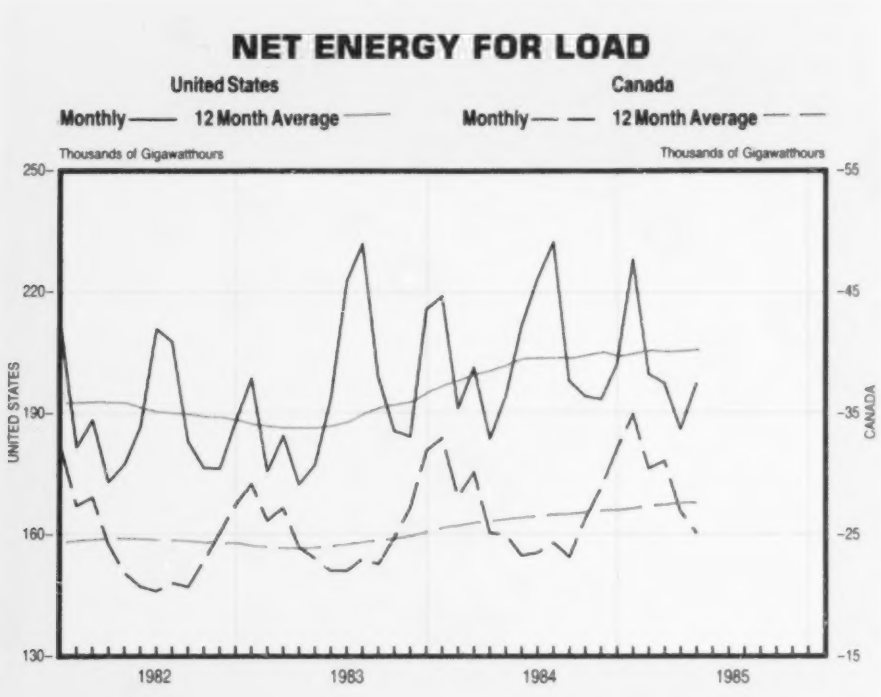


FIGURE 1

FORECAST UNCERTAINTY — A CASE FOR FLEXIBILITY

Electric demand and energy requirements depend on a wide range of factors. They include economic performance, governmental policies, the effect of new technologies, population growth, customer conservation efforts, lifestyles and demographics. Since each of these factors is itself uncertain, the overall effect on future electric requirements is a compounding of uncertainties.

Electricity is unique among energy sources in that it must be produced at the precise moment it is required; it cannot be produced in excess at times of low demand and saved for use at times of peak demand. Thus, the capability to produce electricity must be in place when the need for it arises. A reliable supply of electricity is vital to the health and well-being of a modern economy — when demands cannot be served, industry, commerce and residential customers suffer.

Given the uncertainty of future electric requirements and the critical nature of an adequate electric supply, it is important that utilities have flexibility to respond to changing trends in future demand.

GENERATING CAPACITY AND FUEL

Planned capacity additions in the United States for the 10-year period are about 17,600 MW (or 13.5%) less than reported last year. Reductions in plans for coal and nuclear units account for essentially all of the cutback. In Canada, utilities are planning to add 2,900 MW less capacity, all of this reduction coming in coal and nuclear units.

CURRENT SITUATION

Coal-fueled generating capacity provides more than 50% of the electricity in the United States today, while hydroelectric units are the mainstay in Canada. Despite coal's predominance in the United States, several regions continue to depend heavily on oil or gas. Nuclear energy will grow in importance in some areas of the United States and Canada as new plants are placed in service. The situation in each region is discussed in detail in the "Regional Assessments" section of this report.

PLANNED CAPACITY ADDITIONS

United States' electric utilities are planning to install 113,200 MW of generating capacity from 1985 through 1994.[1] Coal and nuclear-fueled capacity additions amount to 42,200 MW and 46,300 MW, respectively. Canadian electric utilities are planning to install 15,000 MW of generating capacity from 1985 through 1994. Coal, nuclear and hydroelectric capacity additions amount to 2,600 MW, 6,400 MW and 5,400 MW, respectively. These additions are shown in the accompanying figures and tables.

TRENDS

Total capacity planned to be added for the 10-year period is less than shown in last year's 10-year projection. Nuclear projects removed from last year's capacity list include Midland 1 and 2 (1,194 MW) and Marble Hill 1 and 2 (2,260 MW). The schedules for Seabrook 2 (1,150 MW) and Perry 2 (1,179 MW) are under review and are not counted as part of the NERC capacity during the review period. TVA's Bellefonte 2 has been deferred beyond 1994. Other nuclear units and some coal-fired units have been deferred because of lower demand forecasts. Comparison of this year's and last year's projections for 1993 generating capacity are shown in Tables 6 and 7.

There is a trend toward use of smaller units, partly because of an increase in the number of planned oil/gas peaking units. The number of smaller units may continue to increase for several reasons. One is that smaller units take less time to construct and therefore may incur lower financing costs and may allow commitments to be postponed. This is an advantage, considering the uncertainty of load growth and the uncertainty of rate treatment upon completion.

Advantages of smaller units are attainable with fluidized bed combustion (FBC) units as well, and there is utility interest in several FBC demonstration projects. The FBC units also have the advantage of meeting sulphur dioxide (SO_2) limitations without the use of expensive desulphurization equipment.

COGENERATION

Four regions or subregions of the Electric Reliability Council expect to have significant amounts of cogeneration capacity in service by 1994. The total cogeneration in these four areas is expected to reach about 9,000 MW in 1994, and represents about 5% of their total capacity.

	Expected Cogeneration	
Area	Capacity (1994)	% of 1994 Area Capacity
ERCOT	4,270 MW	6.8
New England	1,182 MW	5.3
California	2,527 MW	4.5
MAAC	1,029 MW	2.1

Cogeneration has been used for many years to produce electricity in connection with industrial processes where steam is a requirement. Favorable tax and regulatory treatment in the United States have increased the potential use of cogeneration and small power production. The potential for cogeneration appears to be increasing rapidly. Some reputable parties are estimating cogeneration potential to exceed 20,000 MW. However, the situation is very fluid, and any one of a number of factors could change the amount of

[1]Capacity additions as reported for the April 1, 1985 to December 31, 1994 period in the April 1985 "Coordinated Bulk Power Supply Program" (IE-411) Reports of the Regional Councils.

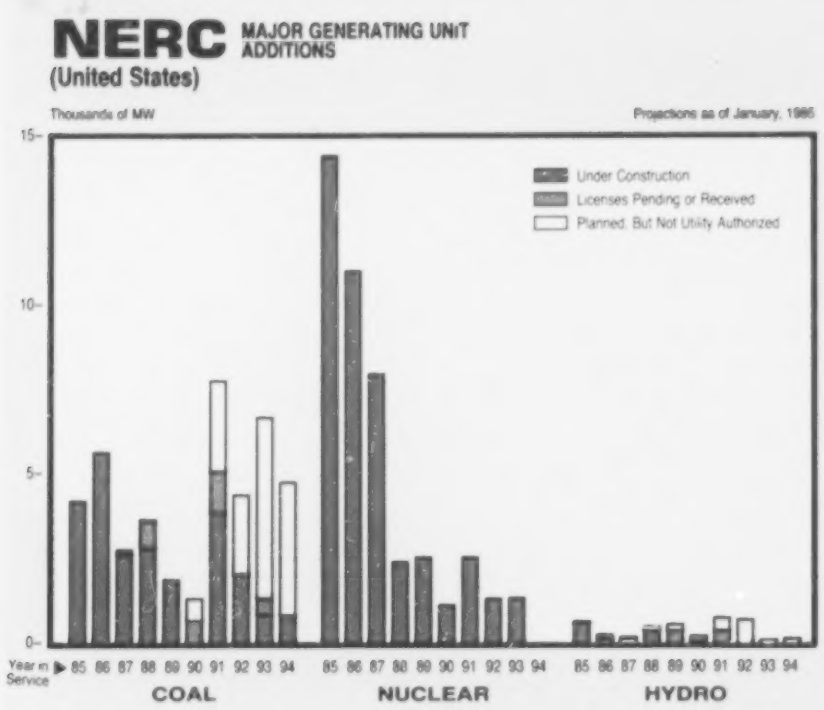


FIGURE 2

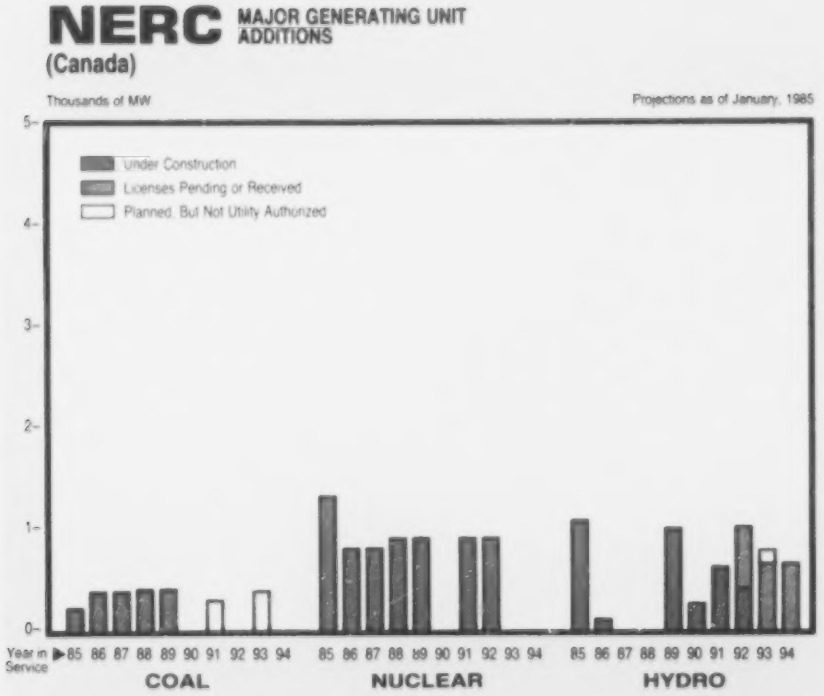


FIGURE 3

cogeneration capacity that is actually placed in service.

The fact that the construction lead time is short may be a significant advantage to the utility, both financially and in the flexibility of the planning process. Of concern is reliability and dependability of cogeneration units as a capacity and energy source, and the long range prospect for continued operation. Since cogenerators are permitted to use natural gas or oil as fuel, their incentive to continue operation will be subject to price variations of these fuels. Many will operate as base load generation and may not respond effectively to the need to reduce output at times of light utility demand or during emergencies. It is anticipated that cogenerators will be more responsive to process needs than to the needs of utility customers for reliable electric service. Many cogenerators will resist participating in voltage and frequency control.

Table 4 NERC Generating Unit Additions, 1985-1994

NUCLEAR[1]	United States			Canada		
	Number of Units	Thousands of MW	% of Total MW	Number of Units	Thousands of MW	% of Total MW
Planned, but not utility authorized	0	0.0		0	0.0	
Regulatory approval pending	0	0.0		0	0.0	
Regulatory approval received, but not under construction	0	0.0		0	0.0	
Under construction less than 50% complete	6	7.0	15.1	4	3.5	55.1
Under construction more than 50% complete	35	39.3	84.9	4	2.9	44.9
TOTAL NUCLEAR ADDITIONS[2]	41	46.3		8	6.4	

COAL	United States			Canada		
	Number of Units	Thousands of MW	% of Total MW	Number of Units	Thousands of MW	% of Total MW
Planned, but not utility authorized	35	14.9	35.3	3	0.9	34.6
Regulatory approval pending	4	2.2	5.2	0	0.0	
Regulatory approval received, but not under construction	5	1.1	2.6	0	0.0	
Under construction less than 50% complete	21	13.6	32.3	3	1.1	43.5
Under construction more than 50% complete	21	10.4	24.6	2	0.6	21.9
TOTAL COAL ADDITIONS[2]	86	42.2		8	2.6	

HYDRO[3]	United States			Canada		
	Number of Units	Thousands of MW	% of Total MW	Number of Units	Thousands of MW	% of Total MW
Planned, but not utility authorized	107	1.5	46.1	2	0.1	2.5
Regulatory approval pending	29	0.5	14.9	0	0.0	
Regulatory approval received, but not under construction	25	0.3	10.1	6	1.9	35.4
Under construction less than 50% complete	12	0.5	14.5	14	2.2	40.7
Under construction more than 50% complete	21	0.5	14.3	6	1.1	21.4
TOTAL HYDRO ADDITIONS[2]	194	3.2		28	5.4	

[1]Seabrook 2 (1,150 MW) and Perry 2 (1,179 MW) are included in these totals but are not shown on the charts of Generating Unit Additions or Generating Capacity By Fuel.

[2]Totals may not add due to rounding

[3]Does not include pumped storage

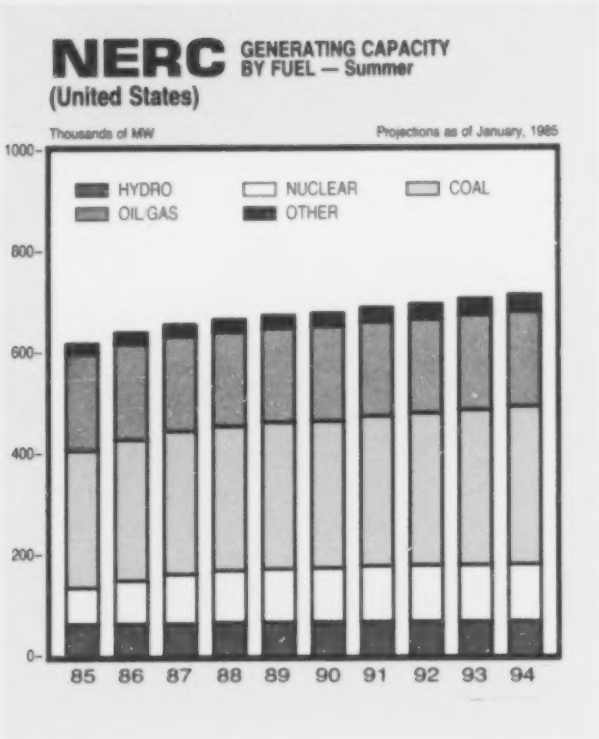


FIGURE 4

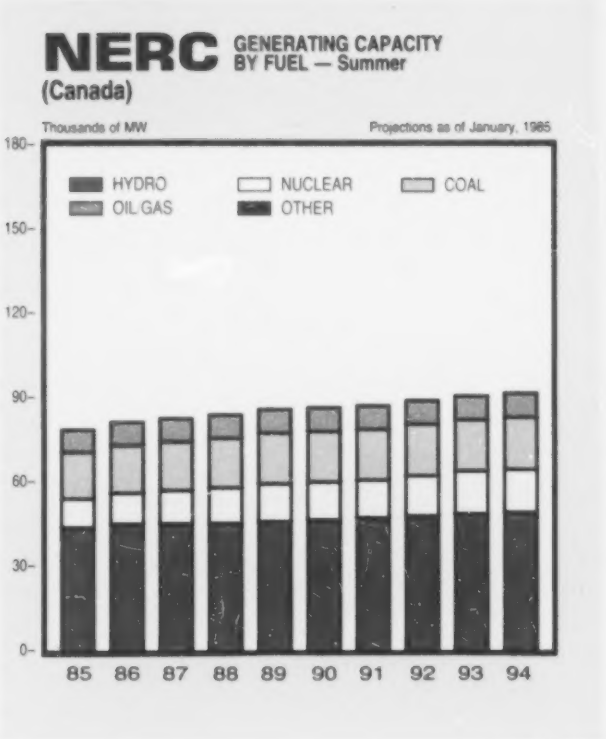


FIGURE 5

Table 5 NERC Generating Unit Additions, Retirements & Conversions, 1985-1994

Thousands of MW	United States	% of Total	Canada	% of Total
Nuclear	46.3	40.9	6.4	42.7
Coal	42.2	37.3	2.6	17.3
Hydro	3.2	2.8	5.4	36.0
Oil/Gas	6.7	5.9	0.6	4.0
Pumped Storage	5.2	4.6	0.0	0.0
Cogeneration	6.6	5.8	0.1	0.0
Other*	2.9	2.6	0.0	0.0
Total Additions*	113.2		15.0	
Retirements	12.4		0.2	
Oil-to-Coal Conversions	4.5		0.0	

*Totals may not add due to rounding

RETIREMENTS

Planned unit retirements over the 1985-1994 period total 12,600 MW, essentially all of which is in the United States. The planned retirements amount to about one year's load growth. Increasing attention is being given to extending the life of existing units and to improving their availability. Such programs are influencing decisions on capacity additions and retirements and account for some of the deferrals and cancellations. The capacity mix of additions between 1985 and 1994 is shown in Figures 4 and 5 for the United States and Canada, respectively.

PROJECTED ENERGY AND FUEL USE

North American utilities expect to provide nearly 3,400 million megawatthours of electricity in 1994. This is over 27% more electricity than was required in 1984. Coal-fired generation is projected to its over-50% share of total electricity generation in the United States by 1994, while nuclear will increase its share to 22%[2] and oil/gas will decrease to 12% as shown in Figure 6. In Canada,

[2]Compared to 1995 projections of 75% for France and 33% to 37% for the U.K., West Germany and Japan, for examples.

Table 6 NERC - United States Installed Generating Capacity - 1993 Summer Comparison of Forecasts

Thousands of MW Fuel Type	This Year's Forecast for 1993	% of Total	Last Year's Forecast for 1993	% of Total	MW Change in 1993 Forecast
Coal	306.5	43.5	312.8	44.4	-6.2
Nuclear	110.4	15.7	115.6	16.3	-5.2
Hydro	68.5	9.7	66.9	9.4	1.6
Oil/Gas	186.6	26.5	183.1	25.8	3.5
Pumped Storage	19.6	2.8	18.8	2.6	0.8
Other	12.6	1.8	13.4	1.8	-0.8
TOTAL	704.3		710.6		-6.3

hydro-powered generation is projected to decrease its share of electricity production to 58% by 1994, with nuclear increasing to 25% and coal decreasing to 16%, as shown in Figure 7.

United States' utilities continue to purchase significant quantities of electric energy from Canadian utilities for mutual advantage. In the four regions where these transactions occur, the transaction supplies from 0.2% of the ECAR load energy requirements to 12% of the NPCC (U.S.) requirements. From a Canadian point of view, the transaction adds 6.4% to the WSCC (Canada) generated energy requirement and 20.1% to the MAPP (Canada) generated energy requirement. The size of the transactions is expected to increase through the 1980's, particularly in NPCC. The impact on reliability of these increased NPCC transactions is being studied by utilities in NPCC, MAAC, and ECAR.

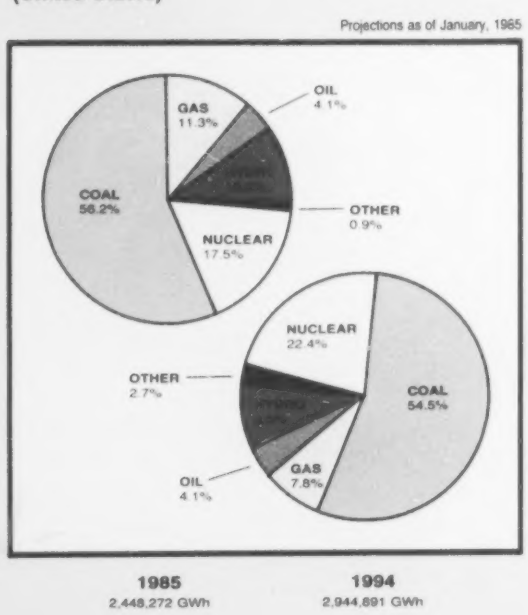


FIGURE 6

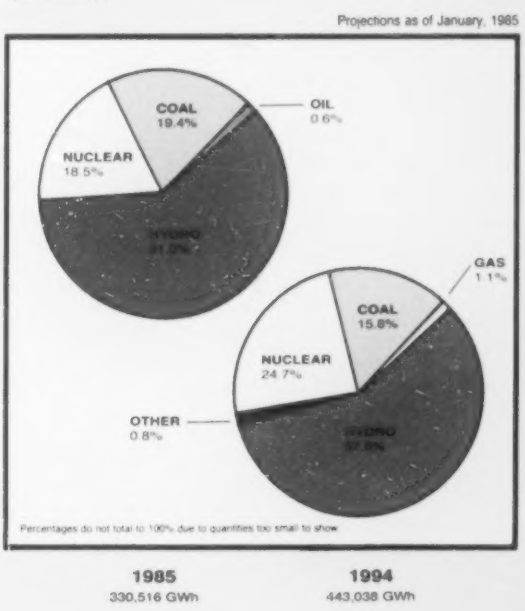


FIGURE 7

Table 7 NERC - Canada
Installed Generating Capacity - 1993 Summer
Comparison of Forecasts

Thousands of MW Fuel Type	This Year's Forecast for 1993	% of Total	Last Year's Forecast for 1993	% of Total	MW Change in 1993 Forecast
Coal	18.3	20.2	19.1	21.5	-0.9
Nuclear	15.1	16.6	15.3	17.2	-0.2
Hydro	48.8	53.8	46.3	52.0	2.6
Oil/Gas	8.4	9.3	8.1	9.1	0.3
Other	0.1	0.1	0.1	0.1	0.0
TOTAL	90.7		88.9		1.8

ASSESSMENT OF POWER SUPPLY ADEQUACY

In the United States, installed generating capacity is forecast to be near the minimum acceptable levels in some regions by 1994 and may not be sufficient unless certain important actions are taken. In Canada, electricity supply is judged to be adequate for the entire 1985-1994 period.

Priorities for assuring adequacy of electric supply in the United States for the 1990's include keeping existing generating units in operation, maintaining schedules for units under construction and shortening lead times for the siting, licensing, and constructing of new units.

REQUIREMENT FOR FUTURE ADEQUACY

Electric power supply in the United States during the 1985-1994 period will be adequate if utilities can:

Complete and place in service generating units which are well along in construction.

Use life extension, refurbishment and maintenance programs to get the most out of existing generating equipment.

Develop capacity alternatives having shorter lead times for licensing and construction.

Resolve the acid rain question in a manner that will not result in an undue reduction of existing coal-fired capacity, or in lengthy outages for retrofitting units.

Commit to new capacity that has a demonstrated need.

COMPLETE UNITS NOW UNDER CONSTRUCTION

In Canada, 6,400 MW of nuclear capacity, 1,700 MW of coal-fired capacity, and 2,100 MW of hydro capacity presently planned for service over the next ten years is already under construction. The expectation is very high that all or most of this capacity will come into service on schedule.

The United States' situation for units under construction does not appear as favorable. At present, there is 46,300 MW of nuclear capacity under construction. During 1984, 3 units totaling 2,383 MW were indefinitely delayed and 8 units totaling 9,040 MW were canceled. In addition, 26 units had their service dates delayed an average of 7 months each. Of the 16 units scheduled for commercial operation during 1984, only 7 (totaling 7,566 MW) were placed in service. Based on continuing difficulties in satisfying all regulatory requirements and obtaining operating licenses, the service dates of the remaining nuclear units must be considered questionable.

United States' utilities also have 24,000 MW of coal-fired capacity under construction. These units are not immune to problems, but the outlook is much brighter than for nuclear. Since last year, 18 coal-fired units totaling almost 10,000 MW were placed in service. However, 8,300 MW of coal-fired capacity was dropped from the forecast while less than 3,700 MW was added; 24 units totaling 12,500 MW were delayed an average of 20 months each. Another 18,200 MW of coal-fired capacity is planned but not yet under construction. It is questionable if all of that amount can be licensed and constructed by the time it is needed. Construction was begun on only one large coal-fired unit in the past year.

Recently, some regulators have not allowed costs for coal and nuclear units to be included in rate base. In other cases, extended phase-in periods have been required. These actions are preventing or discouraging utilities from committing to further construction. Reliability is likely to suffer in the process.

ACID RAIN

In the past, the effect of acid rain legislation was considered to be heaviest east of the Mississippi River. However, calls for further restriction in SO_2 and NO_x emissions are being voiced in other areas as well. In the United States, there remains a need to further document cause-effect relationships, assure effectiveness of any program offered for adoption, and achieve consensus regarding societal costs. Further emission restriction would lower unit availability and increase the power required to operate new emission control equipment. Any control equipment added to existing plants would require extensive unit downtime while installation was made. While the outages required for retrofitting units with new control equipment can be scheduled in phases, some replacement capacity would still be required.

SHORTEN LEAD TIMES

A reduction in the time between commitment and operation of a generating unit (lead time) would be of great benefit in capacity planning. In fact, it could be considered the single most important step needed to assure future electric supply adequacy.

Smaller units are also being considered as a means of shortening the time between commitment and operation and reducing capital requirements. The smaller units' greater ratio of shop labor to field labor should minimize construction time. This is particularly true of combustion turbines. Another type of unit being studied uses fluidized bed combustion, which can burn a wide range of coals or even refuse in an environmentally acceptable manner. The smaller units should make siting easier, and also ease financing of projects.

LIFE EXTENSION AND REFURBISHMENT

For various reasons, many systems have made studies of extending the life of existing units or of doing major maintenance to improve availability. Some have entered into programs to implement the results of the studies. These programs have the effect of increasing capacity in a short period of time. They can also allow delaying the decision date on new capacity additions.

CAPACITY MARGIN

Capacity Margin is the difference between peak demand and total demonstrated capacity. When expressed as a percent, **Capacity Margin** is divided by the total demonstrated capacity. Besides serving the demand, the total demonstrated capacity is needed to allow for generating equipment outages — either scheduled for maintenance or unexpected -- for equipment deratings due to various causes and for differences between actual demands and those forecast.

TRANSMISSION ISSUES

The transmission systems continue to be heavily loaded a high percentage of the time to maximize economy energy transfers. As a result, there is a greater vulnerability to system disturbances and customer service interruptions. Building more transmission lines would increase the capability to transfer economy energy and, at the same time, increase the capability to respond to emergencies. However, there are impediments and disincentives to planning, licensing and constructing new lines.

HEAVY TRANSFERS

The attempt to reduce the amount of electricity generated by oil-fired units began with the oil embargo of 1973 when the rapidly rising oil and gas prices caused large differences in energy costs. By transferring significant amounts of coal or hydro-generated electricity to replace that generated from oil and gas, sizable savings were achieved, even after transfer costs were considered. These savings were divided between purchaser and supplier to benefit the customers of both utilities.

Energy cost differences between regions continue to justify very high transfers. For example, Northeastern utilities rely heavily on imports of electricity from Canada. Southeastern systems transfer large amounts of electricity among subregions. The Mid-Atlantic area imports significantly from the central U.S. and vast amounts of Pacific northwest hydro-generated energy are transferred to the Pacific southwest. Figure 8 illustrates actual 1983 and 1984 transmission use in MAAC and WSCC, compared to transmission capabilities in those regions.

These transfers are expected to continue through the mid-1990's, based on present estimates of load growths, fuel prices, and generator additions.

RELIABILITY

Transmission is used to exchange large quantities of electric energy during localized generating capacity shortages. For example, severe cold weather in the winter of 1984-85 struck broad regions of the eastern half of the United States and caused some systems to lose generating capacity due to frozen equipment and fuel supplies. At the same time, customer heating loads climbed to new highs. This combination created a shortage in electricity supply. Unaffected utilities quickly increased available generation and used the transmission network to deliver power to areas where supply was in jeopardy. Transmission was also crucial in serving the customers in Texas and the Gulf States during the recent severe winter.

Excessive transactions between pools and regions can adversely affect power system reliability. While a severe disturbance during normal transmission loading may go unnoticed by customers, the same disturbance occurring while the system is heavily loaded is more likely to cause consequential outages and customer interruptions. Compounding the effect is the phenomenon of parallel path flow, also called loop flow or circulating flow. When two interconnected utilities have transmission ties with a third utility, and are transferring energy, the adjacent utility transmission system will be a path for power flows in parallel with the main path. For example, Figure 9 shows the effect of non-simultaneous flows from ECAR to MAAC and from Ontario Hydro to NYPP. Coordinated planning and control of schedules within and between regions is a constant activity of system operators and planners to control line flows to safe levels.

IMPEDIMENTS TO NEW TRANSMISSION

A number of proposed key transmission additions in various parts of the country, which could both increase transfer capability and improve reliability, are being denied or delayed.

Among general impediments to the construction of new bulk power transmission lines are:

- Uncertainty of Future Benefits: Justification of new transmission lines is accomplished through consideration of economic benefits and reliability requirements. Today, regulators and utilities tend to discount uncertain future benefits such as prospective but non-contract power transactions and maintaining regional reliability. Consequently, transmission lines that might have been built in the past on a reasonable expectation of future benefits are not likely to go forward today.

- Licensing Procedures: The lengthy regulatory process for issuing licenses for new transmission hampers new construction. Likewise, open-ended

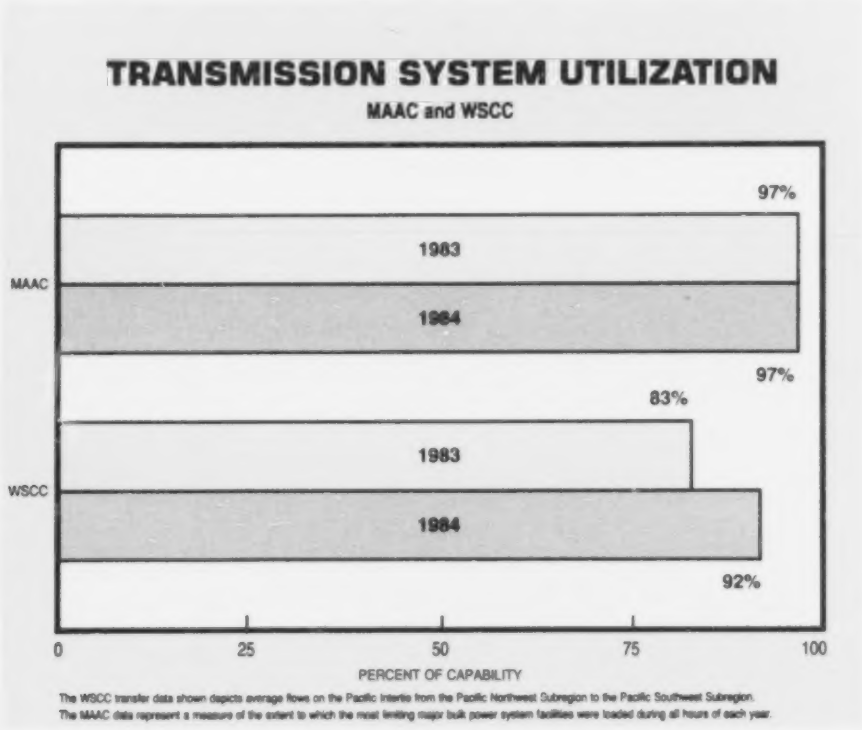


FIGURE 8

regulatory processes, wherein an action can be re-opened even after a license has been issued, present serious impediments to the timely construction of new facilities.

- Conflicting Jurisdictions: Conflicts among local, state and federal agencies in licensing matters can result in extensive delays in authorizing new transmission lines. Similarly, where transfers between two systems result in the need for reinforcements in different jurisdictions, extensive delays generally result.

- Lack of Incentives: Regulatory treatment which assigns the economic benefits of a new facility solely to the customer, while the utility bears all of the risks, creates a disincentive for planning new transmission.

Examples of specific projects that have been delayed:

- The **Washington, D.C.** 500 kV loop has been delayed for several years. The development of an EHV transmission network in the Washington, D.C. area would significantly increase the ability to import energy into MAAC. Completion of the loop is now scheduled for 1991. Efforts to accelerate this schedule are being pursued.

- The delay in restarting Three Mile Island #1 (near **Harrisburg, Pa.**) creates an impediment to transfers. In addition to providing low cost electricity, TMI is important for voltage support. Without this voltage support, the utilities in MAAC are not able to replace as much oil-fired generation in its eastern area with coal-fired electricity from western Pennsylvania and Ohio.

- The 500 kV transmission expansion in **Ontario** has been delayed more than 18 months as a result of a decision by the Supreme Court of Ontario. The delay of this transmission impacts the reliable supply in southwestern Ontario and reduces the important transfer capability between Ontario and Michigan.

- Construction of a 500 MW dc tie between ERCOT and the Southwest Power Pool is being delayed by

a **Texas** PUC order to provide a more comprehensive examination of possible health effects.

- The Belle River-Jewell 345 kV line in **Michigan** is necessary to deliver power from the new Belle River Power Plant to the system. Without this line, restrictions in power transfer from Ontario Hydro to Michigan are required during certain circuit outages and adverse weather conditions. Application for a construction permit was made in January 1983 and approved by the Michigan PSC for an in-service date of July 1985. Currently, the line is held up in court action for township zoning approvals and property condemnation which is estimated to delay the completion until March 1987.

- The 39-mile Tewksbury-Seabrook 345 kV line will be needed to deliver power to **New Hampshire and Massachusetts** when the Seabrook unit comes on line. There is a high probability that the line will not be completed in time due to several uncertainties including regulatory and financial problems. This delay will force the use of costlier generation patterns to prevent system instability.

- The Noxon-Pine Creek 230 kV #2 line in the **Pacific Northwest** has been delayed until October 1987 due to permit acquisition problems with the U.S. Forest Service and due to budget constraints. Delay of this project in conjunction with delay of Bonneville Power Administration's Taft-Bell 500 kV transmission line may lead to serious line overloading problems for certain outage cases when all four Colstrip generating units are on line in 1986.

- The existing transmission interconnection between **Colorado and New Mexico** is a weak transmission link in the eastern area of the WSCC. The completion of the Rifle-San Juan 345 kV line in 1986 after a two-year delay will significantly strengthen the interconnection providing a major improvement in reliability. Until the line goes into service, power flows through Colorado will continue to stress existing facilities requiring generation curtailments

PARALLEL PATH FLOW

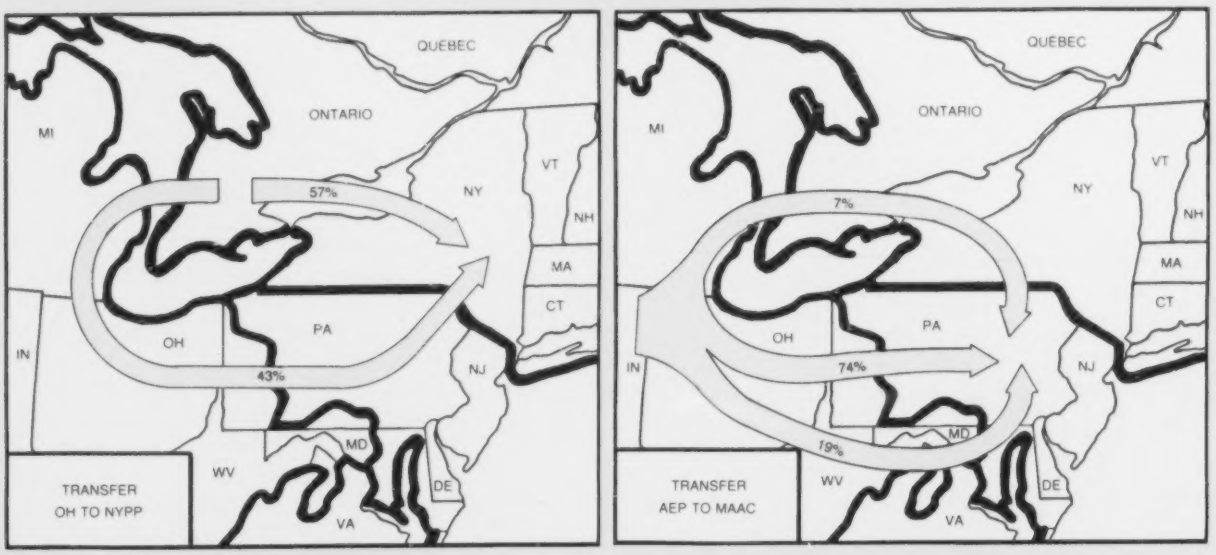


FIGURE 9

and resulting in separation, loss of load and generation for certain system disturbances.

- The Devers-Valley-Serrano 500 kV line in **southern California** is presently under construction and planned to be operational in 1986 after a two-year delay from the original planned date of 1984. The delay is a result of a licensing proceeding spanning four years. The license was finally issued on October 3, 1984. The line is required for local reliability. In addition, there is a resulting 400 MW gain in transfer capability from Arizona to California. The gain in transfer capability will be delayed until the full project is in operation at 500 kV.

An example of where impediments have been overcome and where transmission expansion has been successfully accomplished is in Florida. Since 1980, over 900 miles of 500 kV transmission has been added in the Southern and Florida Subregions of SERC in order to support sales of coal-generated power to oil-dependent areas of Florida. Figure 10 illustrates how energy transfers have increased and system separations have decreased through transmission expansion since 1980.

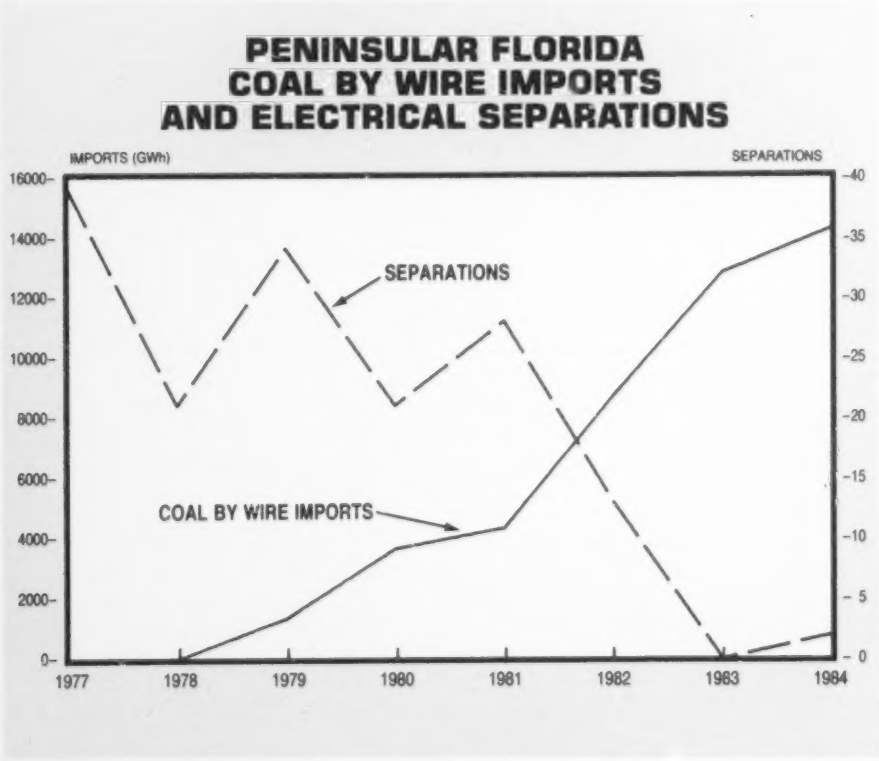


FIGURE 10

A SUBSTITUTE FOR NEW TRANSMISSION

Impediments to building new transmission coupled with the incentives to increase transfer capability have resulted in the increased application of innovative devices and methods involving complex control and protection systems. These special devices and techniques are used to disconnect generation, open lines, shed loads, and to operate other control devices. Initially, these devices and schemes (collectively labeled "Special Protection Systems") were used as temporary fixes to provide the additional time needed to complete new transmission lines. This temporary use has evolved into more permanent applications and dependencies. Experience has shown that the reliability of these devices has not been as good as desired and when they have misoperated they have caused or extended a number of outages.

SPECIAL PROTECTION SYSTEMS

Special Protection Systems (SPS), also known as Remedial Action Schemes, are designed to perform system protection functions other than the isolation of electrical short circuits. SPS are installed to permit higher levels of power flow on the transmission system in those instances where additional faciiities cannot be justified or built or have been delayed. They may be used to maintain system stability or control power flows on critical facilities immediately following a disturbance or other abnormality on the system. SPS allow higher power transfers and the use of more economic generation. However, they can expose a system to greater reliability risks, since the integrity of the system depends on their correct operation.

THE OUTLOOK

Special Protection Systems and restoration techniques are being used to raise interconnection loadings and to reduce customer costs. Faced with impediments to the construction of new transmission lines, it is expected that utilities will take more risks and customer interruptions will increase. The outlook is for higher loadings and declining reliability.

OPERATIONS

The balance between electricity reliability and cost is changing. One of the continuous functions of system operators is keeping abreast of, and controlling, that balance. Increasing economic pressures to get more out of existing equipment and systems will increase the risk of more frequent and more severe customer service interruptions. To meet this growing challenge, electric utilities in North America, through their regional operating groups and the Electric Reliability Council, are continuing to develop, implement and review effective operations planning techniques, assess and upgrade system monitoring, communications and control capabilities, and train system operators to deal effectively with the challenges ahead.

LARGE ENERGY TRANSFERS

Utilities are using their transmission networks to transfer large amounts of lower cost electricity to other systems. Because of the increasing magnitude of these transfers, and the fact that these transfers are taking place a high percentage of the time, the risk of system disturbance and customer service interruption is greatly increased.

Most of the transmission lines that tie utilities together were built to improve reliability by permitting one utility to help another during a generating capacity emergency of short duration. Transmission systems are still used for this purpose, but even greater use is being made for economy energy transfers. These transfers result in savings which lower the cost of electricity to the customer, but often do so at the expense of reliability. With transmission systems loaded up to their maximum safe limits most of the time, their ability to respond to severe disturbances is reduced.

With the trend of heavy transfers expected to continue, system operators will be forced to cope with a transmission network that has less margin to deal with unusual emergencies than it has had in the past.

GENERATING CAPACITY MARGINS

Generating capacity margins are expected to decline, approaching near minimum acceptable levels in some areas by the mid-1990's. This, in turn, will mean that system operators will have less operating margin to work with to meet customer demands on an hour-to-hour and day-to-day basis. Already, utilities are relying more on interruptible load and other load management techniques to compensate for lower operating margins. If priority continues to be given to economics over system reliability, the quality of customer service will most certainly decline.

SPECIAL PROTECTION SYSTEMS

Many of the disturbances which have occurred in the past several years have been related to misoperation of relays or Special Protection Systems. In an effort to get more out of existing transmission and generation systems with minimal capital expenditures, utilities are increasing the application of Special Protection Systems to allow operating their transmission systems at higher levels than normally considered acceptable. Particularly close attention must be given to the design, maintenance and testing of these systems to mitigate adverse effects on system operation.

VOLTAGE SUPPORT AND REACTIVE SUPPLY

One often overlooked effect of large electricity transfers is the need for sufficient reactive power to adequately support system voltages. Since the loading of many transmission facilities is much higher than anticipated at the time the facilities were planned, parts of the transmission system are being operated with voltages barely adequate to maintain electric system stability. More attention needs to be focused on reactive supply in the various operational planning studies which are performed, especially in those cases that depend on remote reactive sources or those that involve heavy power flows.

MONITORING AND CONTROL OF OPERATING CONDITIONS

With greater electricity transfers from one utility to another, and with the prospect of lower operating margins, utilities must give more importance to system monitoring and control. In many cases, disturbances can be aggravated by lack of sufficient monitoring and failures of communication systems both within the utility and with other utility systems. Inadequate and unreliable information systems lead system operators to incorrect conclusions about their system's conditions.

Among the ways system operators have to deal with these deficiencies are: provide for and require monitoring of all critical system points and conditions; establish clear intra-utility communications procedures for system operators; use the available interutility and interregional communication systems, provide adequate backup communications facilities and power supplies; and review dependence on telephone company equipment for critical communications channels. System operators must know constantly what the situation is with their facilities and the facilities of neighboring utilities.

Improvements in monitoring and control are continuing through the use of modern computers and software, better telecommunications facilities, and redundancy in design. The Electric Power Research Institute has joined with the Electric Reliability Council and its member systems in furthering software development and application. Many utilities have already established computer-to-computer links to achieve almost instantaneous data exchange.

PLANNING FOR FUTURE OPERATIONS

As generation and transmission margins decrease, system operations will become more complex and demanding. The development and application of new tools and techniques will allow the most efficient and reliable use of electric generation and transmission equipment. If this preparedness can be accomplished, the risk of cascading, widespread blackouts can be minimized. Nevertheless, the balance between reliability and economy has most certainly changed, and customers may very well experience controlled but more frequent customer service interruptions.

ECAR

1984 STATISTICS	
Summer Peak — MW	65,851
Winter Peak — MW	67,349
Annual Energy — GWh	383,029
Installed Capability (Summer) — MW	90,115

ECAR will have a reliable power supply throughout the 1985-1994 period as long as there is no significant change in the performance of existing units, and as long as projected additions are completed on schedule.

ADEQUACY APPRAISAL SUMMARY

The ECAR Region will have an adequate and reliable power supply throughout the 1985-1994 review period provided that the availability of generating equipment remains at or near recent levels and generation and transmission additions are completed as scheduled. By 1994, ECAR's capacity margin will be approaching the minimum level required to serve the projected loads in a reliable manner.

The overall reliability of the Region could degrade to an unacceptable level near the end of the review period if unavailability of generating equipment should increase significantly, if acid rain control strategies result in substantial capacity deratings, and (or) if there are delays in the planned generation and transmission additions.

DEMAND PROJECTIONS

The upturn in industrial activity that started in mid-1983 and continued through 1984 contributed to higher than expected peak demands. The 1984 summer and 1984/1985 winter aggregate peak demands were 2.9% and 4.8%, respectively, over forecast.

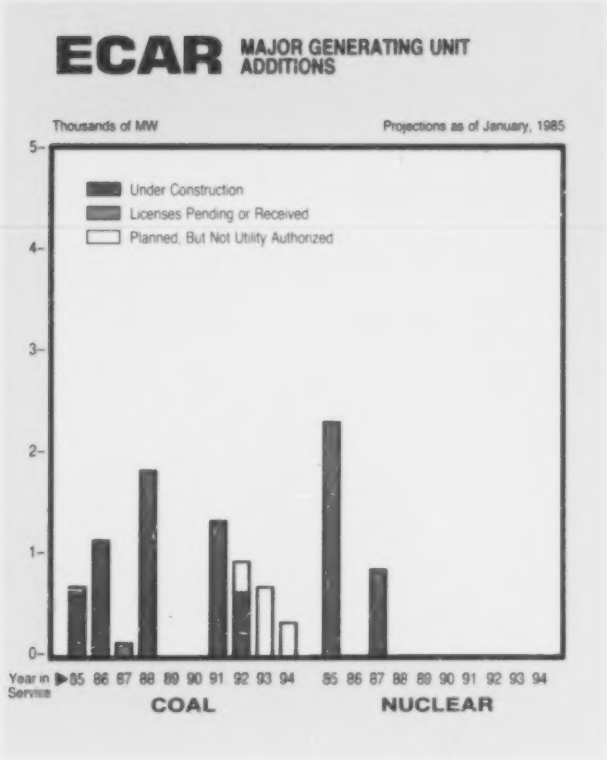
The aggregate of the demand projections provided this year by systems in ECAR shows that the Region is expected to be summer peaking throughout the 1985-1994 period. This differs from the aggregate of the projections provided in previous years where each winter's peak demand either equaled or exceeded the previous summer's peak demand. Furthermore, the current projection for the 1985 summer peak demand (68,200 MW) is approximately 3% higher than last year's projection for the same season.

The average annual growth in peak demand for the period 1985-1994 is projected at 2.0% for the summer and 2.1% for the winter, rates which are approximately 0.4% lower than one year ago. The result is that the demands projected for the later years of the 10-year period are approximately the same as last year. Projected annual energy requirements exhibit a similar trend.

RESOURCE ADDITIONS

Last year, five nuclear units that were well along in construction were removed from capacity projections. These were Marble Hill 1 and 2, Midland 1 and 2, and Zimmer No. 1* — totaling approximately 4,400 MW. Regulatory uncertainty and retrofit requirements, along with resultant cost escalation, have combined to produce a situation whereby it was not practical to complete these units.

*A decision was subsequently made to convert this unit to a 1,300 MW coal-fired unit.



Approximately 3/4 of the projected major capacity additions during the review period are scheduled to be placed in service during the initial four years. Three nuclear units totaling approximately 3,100 MW are scheduled to be placed in service in the 1985-1987 period.

Six major coal units which are in an advanced stage of construction (approximately 3,600 MW) are scheduled for completion in the 4-year period 1985-1988. The jointly-owned (840 MW share) Bath County pumped storage plant is scheduled for 1985 completion.

There are no major additions in 1989 or 1990. Zimmer 1, originally designed as a nuclear unit, is now planned to be installed in 1991 as a 1,300 MW coal-fired unit. During the 3-year period 1992-1994, only two 300 MW, one 600 MW and one 650 MW coal units are projected for the entire Region. Construction has been started on only one of these four units, and the potential exists that one or more could be either deferred or canceled due to difficulties in financing.

During the 1990-1994 period, 1,140 MW of combined cycle and combustion turbine installations are projected. This is approximately 400 MW higher than appeared in last year's projections. In addition, 275 MW of cogeneration and small power producers is expected. This is the first time that these two types of capacity additions have appeared in an ECAR projection.

IMPACT OF PROPOSED ACID RAIN LEGISLATION

In recent years, ECAR has prepared assessments of the impacts that proposed acid rain legislation would have on reliability and adequacy of bulk power supply in the ECAR area. Because of the great uncertainty about the final regulations which might be promulgated and the wide variation in possible control strategy alternatives, a scenario approach was adopted which encompassed the range of conditions that are apt to be encountered.

One analysis was developed on the assumption that sulfur dioxide emissions would be limited by 1994 to 40-50% of the 1980 emission levels. This analysis indicated a very adverse impact on the adequacy of ECAR generating capacity. In order to maintain a reliability level comparable to that provided by the current 10-year plan, approximately 7,000 to 10,000 MW of additional generating capacity would be required by 1994.

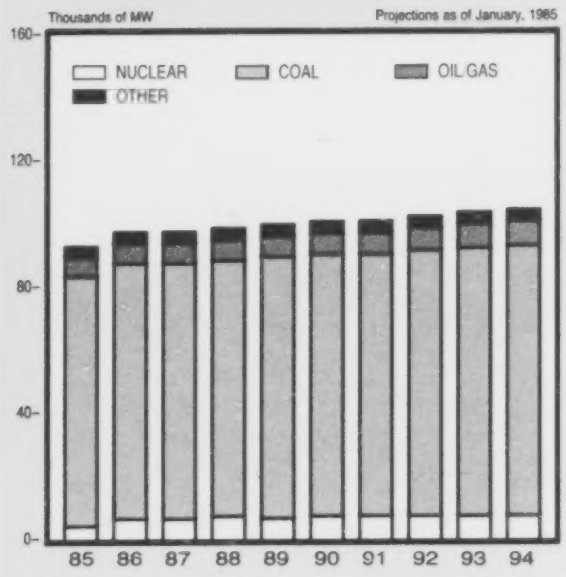
This capacity would be needed to offset the negative effects of the reduced availability of generating units due to the addition of the flue gas desulfurization equipment and to replace capacity which would be lost because of either premature retirement or derating of generating units due to "air quality" modifications. The additional capacity requirement represents a 60 to 80% increase over the generating capacity additions already scheduled during the 1985-1994 period. Lead time and capital constraints may preclude installing this additional capacity causing reliability to be degraded.

ADEQUACY OF PROJECTED GENERATING CAPACITY MARGINS

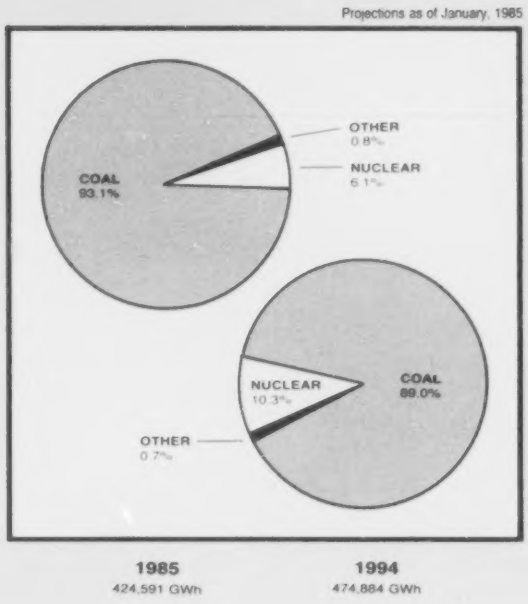
Extensive appraisals of the adequacy of projected generating capacity margins have been carried out for the ECAR Region based on probabilistic techniques and procedures. The major input parameters for these appraisals are the regional load pattern, the status of scheduled generating unit additions, the projected planned maintenance of generating units and the random unavailability of generating equipment.

ECAR members recognize that maintaining or improving availability of generating equipment is essential if the capacity margins currently projected for future years are to prove adequate. In this regard, the average total availability rate of generating capability in ECAR for the non-holiday weekdays during the year has improved from a low of 68% in 1978 to over 77% in 1984. This increase reflects the impact of improvement programs, however, environmental restrictions and any mandated additions of emission control equipment may make it increasingly difficult to improve upon or even maintain the current availability level.

ECAR GENERATING CAPACITY BY FUEL — Summer



ECAR ELECTRIC GENERATION BY FUEL



The 1985 ECAR appraisal shows that if the projected load and capacity conditions materialize, the ECAR criterion for judging the reliability and adequacy of the projected installed generating capacity will be satisfied throughout the 1985-1994 period as long as the average total availability rate exceeds about 73%.

ENERGY AND FUEL

Coal is projected to continue to be the predominant energy generation source for ECAR over the next ten years, while nuclear is projected to increase its share of total energy generation, as seen in the accompanying charts.

The high dependence of ECAR member systems on coal-fired generation makes it imperative that continuity of future coal supply be maintained and systems be permitted to burn the significant quantities of locally produced coal needed to satisfy the future electric energy requirements in the Region.

The availability of materials and services for the various phases of the nuclear fuel supply cycle (uranium conversion, enrichment and fabrication) will continue to be adequate to meet requirements in ECAR for the foreseeable future. However, the issues involving spent fuel storage and disposal must still be resolved.

TRANSMISSION SYSTEM

The pattern of growth for the systems in the ECAR Region has led to the development of an extensive and reliable high voltage transmission network that is interconnected with the networks in neighboring regions at various voltage levels. The EHV portion of the network in ECAR consists of over 1,800 miles of 765 kV, over 800 miles of 500 kV and over 11,600 miles of 345 kV.

The ECAR member systems have developed plans to assure the continued development of a reliable and well-interconnected transmission network. These plans call for the addition of approximately 200 miles of 765 kV, 300 miles of 500 kV, and 900 miles of 345 kV transmission during the 1985-1994 period. The addition of these facilities will create a number of new interconnections between systems within ECAR and between ECAR systems and those in other regions.

Public opposition and governmental siting requirements cause difficulty in obtaining rights-of-way which can influence the timely installation of new transmission. If it becomes necessary to defer or cancel a number of planned major additions due to right-of-way or financial constraints, the reliability of the bulk power supply in the ECAR Region will deteriorate.

The fuel cost differentials that exist between the coal-fired generation in ECAR and the oil-fired generation located to the east of ECAR create an incentive for economy transfers which cause energy flow patterns that were not anticipated at the time the systems were originally planned. The long duration, multi-party economy transfers for the purpose of oil displacement have become an important consideration in the operation of the interconnected transmission network.

In addition to these long duration energy transfers that are scheduled well in advance, significant amounts of energy transfers are undertaken on a daily and even hourly basis between and among ECAR systems and systems in other regions. Some portions of the bulk transmission network are routinely subjected to significant changes in both the magnitude and the direction of the energy transfers. ECAR is actively participating with its neighboring regions in carrying out system performance studies to examine the ability of the interregional network to support the many long duration energy transfers expected. Through such studies, coordination procedures and operating guidelines are being developed and improved to assure that the interconnected network will be operated in a reliable manner.

OPERATIONS

Extensive intersystem and area communication facilities are used by ECAR and its members to coordinate normal and emergency system operation among and between the individual power control centers within ECAR and in neighboring regions. The communication/computer network, which interconnects the power control centers and the ECAR office, is used to exchange operating information among the systems and to quickly disseminate abnormal condition reports to all systems (i.e., a sudden loss of generation, the tripping of an important transmission line, or the cause of an unusual transmission system loading pattern).

Several systems are in the process of designing or implementing control centers that will incorporate system security procedures and analytical capabilities to provide operators with the ability to carry out on-line evaluations of system security. ECAR systems, in conjunction with the systems in MAAC, NPCC and SERC, are actively studying the concept of computer-to-computer data links for the exchange of real-time system data. If proven cost effective, implementation of such communication links could greatly expand the base of information available to evaluate on-line system performance, taking into account multi-system operating conditions.

The East Central Area Reliability Coordination Agreement (ECAR) consists of 19 member systems which serve all or parts of the states of Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland and Tennessee.

ERCOT

1984 STATISTICS	
Summer Peak — MW	36,851
Winter Peak — MW	31,937
Annual Energy — GWh	185,283
Installed Capability (Summer) — MW	44,056

Capacity margin in the Region varies from a low of 15.8% (1985) to a high of 21.2% (1987), based on present unit installation schedules during the 10-year period. Member systems are continuing to install capacity, are contracting for cogeneration, and are implementing load management programs as required for demand growth. Capacity margins are above the minimum adopted by the Region, and reliability is expected to be adequate during the 1985-1994 period.

DEMAND AND ENERGY

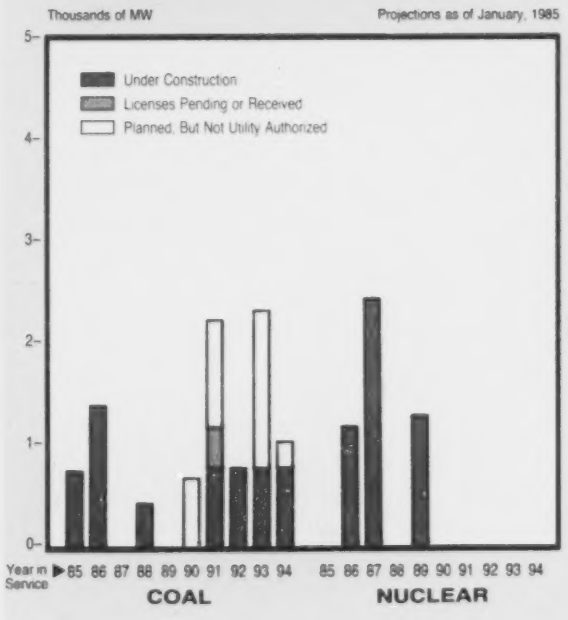
The summer peak hour demand forecast by ERCOT member companies indicates a growth rate in the next ten years of 3.5% per year as compared to last year's projection of 4.0%. Winter peak hour demand is forecast to grow at a rate of 4.3%, indicating the possibility of becoming a winter peaking system sometime after the year 2000. Aggressive load management and conservation programs are being pursued by member companies to reduce the rate of demand growth. Energy growth from 1985-1994 is currently estimated to average 3.6% annually.

GENERATING CAPACITY

To meet anticipated growth in the next 10 years, ERCOT members plan to add 9,400 MW of lignite/coal-fueled generating capacity, 4,800 MW of nuclear-fueled capacity (Comanche Peak 1 & 2, and South Texas 1 & 2), 3,975 MW of cogeneration purchases and 2,450 MW of combustion turbine capacity. The Region will also use nominal amounts of power produced by alternate energy resources, such as refuse, biomass, solar, wind and hydro for total net additions from all sources of approximately 20,850 MW. Of this capacity, approximately 11,400 MW are under construction and the combustion turbine capacity can be installed within relatively short lead time. The status of the construction of cogeneration capacity is not generally known in detail since this capacity is owned by others, but is generally a type of capacity having a short lead time.

Until the early 1970's, the Region depended essentially on natural gas for boiler fuel. Since then, other fuels have been utilized for a diversified fuel mix. The energy generated (by fuels) is projected to be 41% coal/lignite and 58% gas in 1985; and 53% coal/lignite, 34% gas, and

ERCOT MAJOR GENERATING UNIT ADDITIONS



12% nuclear in 1994. Imports from non-ERCOT members, including cogeneration, amount to 11% of net energy for load in 1985 and are projected to be 14% in 1994. Remaining minor amounts of generation are from hydro, oil, and other resources.

GENERATION ADEQUACY ASSESSMENT

Capacity margin in the Region varies from a low of 14.6% (1985) to a high of 20.3% (1987) during the 10-year period. The margin in 1985 is reduced from what it would have otherwise been because of the delay of Comanche Peak Unit No. 1 from 1985 to 1986. Measures are being taken, contractually and operationally, to assure the highest possible availability of generating capacity in the Region.

There are a number of key parameters linked with future adequacy in the Region. Among them are the following:

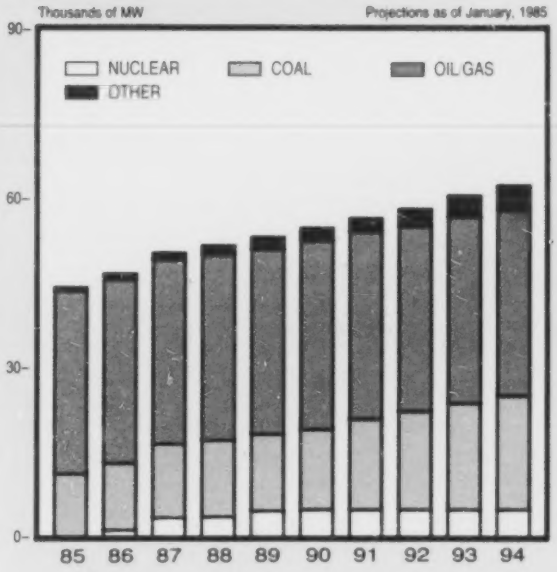
Load Management and Conservation. Member systems are pursuing vigorous programs promoting more efficient appliances, storage systems, and to a lesser degree, direct load control. Utilities are depending on these activities to significantly reduce demand growth in the years ahead.

Completion of New Capacity on Schedule. A balanced program of additions includes base load coal and nuclear capacity and combustion turbines for peaking service. A large portion of the base load capacity is under construction, and the peaking capacity has a short construction lead time. All must be installed on schedule to assure adequacy.

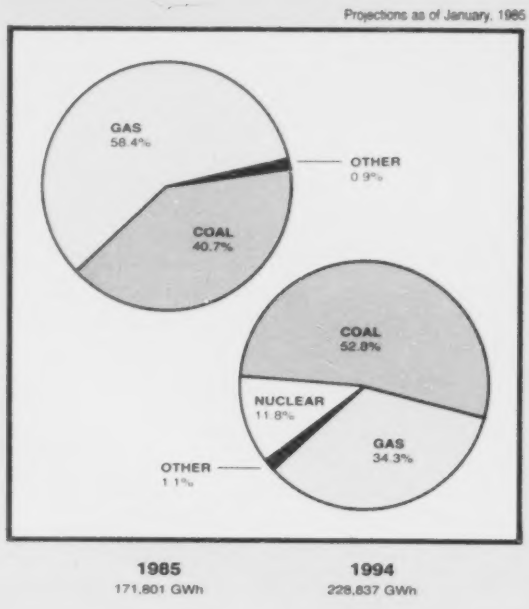
High Availability of Existing Capacity is always vital to reliability. Maintenance programs are designed to obtain high availability and reliability from installed capacity. Life extension programs being considered will likely also benefit availability.

Good Operating Results from Cogeneration. Most systems in ERCOT have limited experience with cogeneration, even though some cogenerators have had years of experience operating their own generation. Partnership of cogenerators and utilities on an unprecedented scale will be required in years ahead. A good operating partnership, essential to adequate reliability, is anticipated.

ERCOT GENERATING CAPACITY BY FUEL — Summer



ERCOT ELECTRIC GENERATION BY FUEL



TRANSMISSION

ERCOT members expect to install about 2,135 circuit miles of 345 kV line in the next ten years, as well as 155 miles of HVDC line. The latter, with its terminals, comprises the south Texas interconnection (500 MW) with Southwest Power Pool. The HVDC line has been delayed by a PUC order to provide a more comprehensive examination of possible health effects. The 200 MW north Texas dc tie between ERCOT and SPP has been in successful operation since December 1984. Planning transmission in connection with the expected 3,975 MW of cogeneration as it develops presents a special challenge in coming years.

OPERATIONS

Coordination among ERCOT control areas improved with modifications in equipment and procedures. The Security Center Computer System became operational with a terminal in each control area. The information system in this computer allows the Security Centers, as well as all control areas, to know the current status and planned status at peak for all generating units. Spinning reserve and hourly loads are also monitored. Additional information, as well as load flow capability, is currently being developed for this computer.

All ERCOT companies participated in joint dispatcher training seminars for the second consecutive year. The opportunity for dispatchers to become personally acquainted and to receive common training is seen as a very positive benefit for improved communication between control areas.

Several Task Forces are also working on ERCOT Operating Guide revisions.

ISSUES

Role of Cogeneration. The role that cogeneration can and should play in the future of electric power supply in ERCOT is being studied and debated by regulators, present and potential cogenerators, and utility representatives. Since cogeneration touches so many areas (such as capacity planning, operations, rates and economics, transmission planning, and fuel forecasting and procurement), it could have a profound impact on developments in ERCOT in future years. Considerable central station capacity in the planning stage may be postponed as additional cogeneration ventures are brought forth and their economics examined. Avoided costs are difficult to determine, and there exists the temptation to pursue short-term economic advantage instead of long-range benefit. Time will be required to fully assess the role of cogeneration in utility service and the effect it has on reliability.

Completion of Units on Schedule. The delay in operation of Comanche Peak No. 1 to 1986 has caused a decrease in capacity margin in ERCOT. While margins are above the minimum reliability criterion on a regional basis, high availability of existing capacity must be maintained for reliability of service. The need for future planned capacity to be brought on line as scheduled is important for reliability and adequacy considerations.

Lead Time for New Generating Capacity. Utilities are increasingly reluctant to commit to new large solid-fueled lignite/coal units because of the long lead times involved. The possibility of a reduced load forecast and uncertain regulatory treatment contribute to this reluctance. As a result, shorter lead time solutions are being increasingly used by some systems where operating conditions permit.

The Electric Reliability Council of Texas (ERCOT) is comprised of 22 municipalities, 49 cooperatives, 6 investor-owned utilities and 1 state agency. These systems operate 85% of the electric generation in Texas and serve approximately 195,000 square miles – 73% of the area of the state.

MAAC

1984 STATISTICS	
Summer Peak — MW	35,442
Winter Peak — MW	33,384
Annual Energy — GWh	186,034
Installed Capability (Summer) — MW	46,183

Projections of future MAAC conditions indicate that the system should meet reliability objectives. Uncertainties that could affect reliability include: load requirements exceeding forecast, planned generation and transmission additions not materializing, coordinating parallel path flow with adjacent systems and the delay in returning to service of Three Mile Island No. 1. These uncertainties would also result in greater dependence on oil-fired generation even though significant oil-to-coal unit conversions have occurred.

DEMAND PROJECTIONS

The Region has traditionally been summer peaking. The summer peak is expected to exceed the preceding winter peak by 6.7% in 1985. By 1994, the summer peak is forecast to exceed the preceding winter peak by 5.7%. However, the Region is not expected to cross over to winter peaking until the early 2000's.

The summer and winter peak demand growth forecasts for the 1985-1994 period are shown below. Both seasonal peak forecasts have been lowered from last year.

MAAC
Peak Demand Forecast
Growth Rate Comparison (%/Yr)

	Last Year's Forecast ('84 - '93)	This Year's Forecast ('85 - '94)
Summer	1.3	1.1
Winter	2.1	1.9

The summer peak demand experienced by the MAAC Region on June 13, 1984 was 1.9% above the 1983 peak. This was the first time in over ten years that all-time peaks have occurred in successive years. Individual company demand growth rates ranged from 0.6% to 4.9%. Factoring out the abnormal 1984 weather conditions, the 1985 summer peak projection is up 0.5% from 1984.

MAAC energy for the year 1984 was 3.4% above the previous all-time peak year of 1983. The energy had been forecast to be 3.0% over 1983. Long-term energy growth is projected at 1.7% per year.

Actual peak demands and energy figures are shown below with 1985 projections.

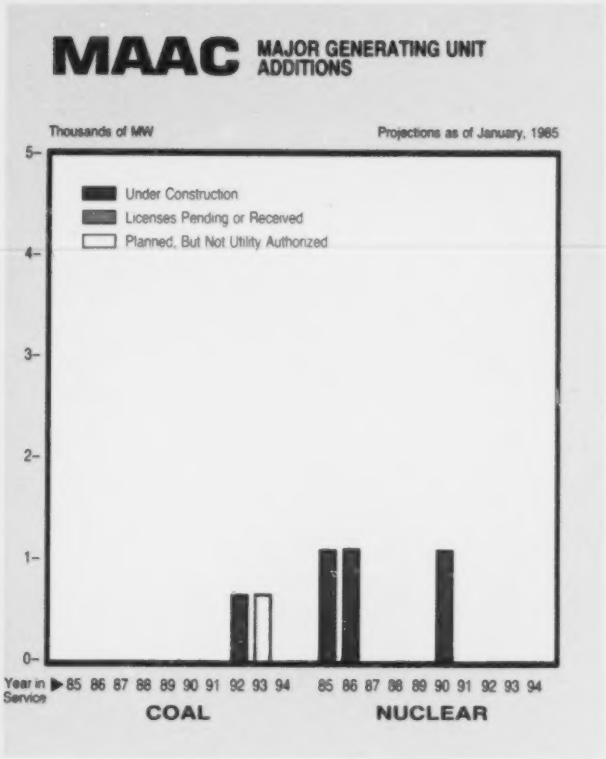
MAAC
Demand and Energy Trends

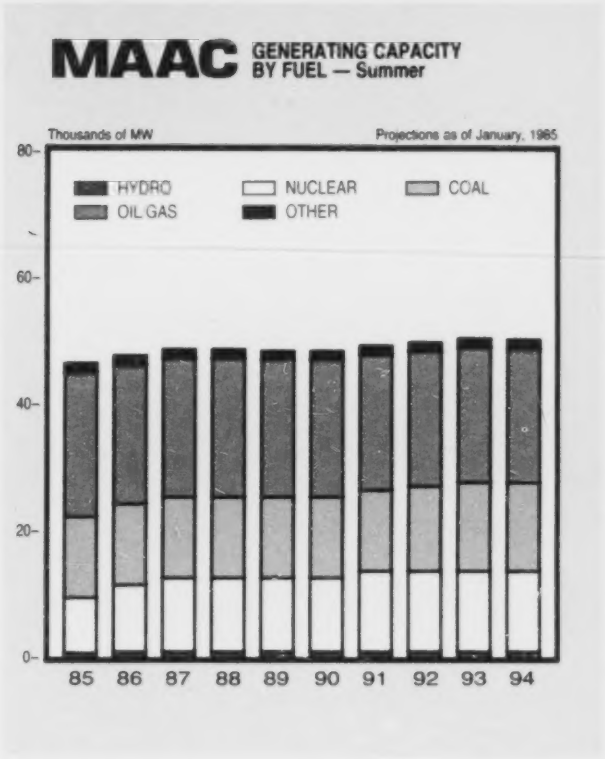
	1983 Actual	1984 Actual	1985 Projected
Peak Demand — MW	34,783	35,442	35,610
Energy — GWh	179,992	186,034	188,274

Although near term projections are up, reduced population growth, higher real energy prices, and consumer energy use changes are all contributing factors to a lower 10-year load growth forecast as compared to previous projections. Load management programs already reflected in forecast are expected to reduce loads by approximately 800 MW and 2,000 MW in 1985 and 1990, respectively.

ENERGY PRODUCTION RESOURCES

Brandon Shores No. 1, a 620 MW coal-fired unit, was placed in service May, 1984 and Susquehanna No. 2, a 1,050 MW nuclear unit, went into commercial operation





in February, 1985. These additions bring the existing MAAC capacity to 47,476 MW, with an installed capacity mix of 79% fossil, 20% nuclear, and 1% hydro.

A total of 5,218 MW of new generation is planned to be added to the MAAC system during the review period. These additions include 3 nuclear units totaling 3,177 MW and 2 coal-fired units totaling 1,265 MW. A total of 2,077 MW of capacity is scheduled to be lost due to retirement or derating. As now scheduled, by the summer of 1994, MAAC will have 50,044 MW of installed capacity consisting of 73% fossil, 25% nuclear, and 1% hydro.

All generating capacity committed to be installed during the review period is well under construction. As planned, sufficient generating capacity will be available in the MAAC Region through the 1984-1994 period to serve the MAAC load reliably. Installed capacity margins are forecast to range from 25.0% to 21.5% through the period.

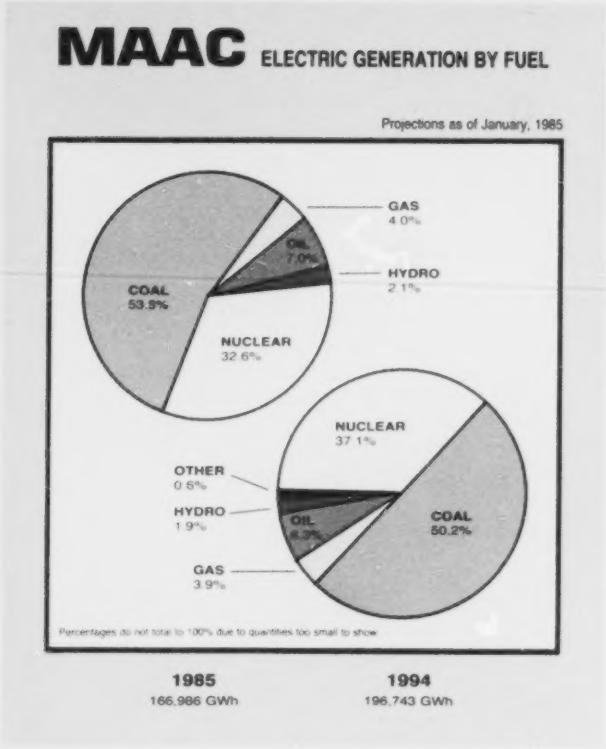
Factors which may adversely affect the adequacy of MAAC's installed capacity are delays in the installation of new generating capacity, disposal of nuclear waste, the enactment of more restrictive regulations governing SO_2 emissions from existing electric generating plants, peak period maintenance, the transition of MAAC from a summer to a winter peaking region, and energy demands exceeding forecast.

Since the last review, a nuclear unit and a coal unit have had their service dates delayed. They are Limerick No. 1 (1,055 MW-nuclear) from April, 1985, to early 1986, and Brandon Shores No. 2 from December, 1988, to May, 1992. The reason for these delays include finalizing an evacuation plan, reduced peak demand forecast and the desire to tailor capacity additions more closely to load growth.

The TMI units have been out of service since Unit No. 2 suffered reactor damage on March 28, 1979. TMI Unit No. 1, rated 776 MW, remains out of service due to a regulatory imposed shutdown and is now projected to return to full power operation early in 1986. One of the consequences of continued delay is the additional consumption of an approximate equivalent of 8.5 million barrels of oil per year.

Sufficient fuel is expected to be available to provide an adequate supply of energy to the Region over the review period. While the supply of nuclear fuel is judged to be secure, issues involving spent fuel storage and disposal must be resolved, particularly for older nuclear units. The passage of the Nuclear Waste Policy Act of 1982 represents a step toward resolving these issues. Continued operation of these units will be assured by meeting the stipulations of this act within the prescribed time frame.

The use of oil for electric generation in the MAAC Region is projected to continue to decrease through the



1980's and then start increasing by 1991. The use of oil as a boiler fuel will expand or contract depending upon changes in energy requirements and the ability of MAAC's coal-fired and nuclear units to operate. For example, if the Region's load grows faster than forecast, the use of oil will increase accordingly. Also, delays in the construction of planned nuclear and coal plants would mean an increase in the use of oil as a boiler fuel as would any restrictions to imports from ECAR. Similarly, regulations designed to control SO_2 emissions that restrict the use of coal as a boiler fuel will cause increased use of oil.

With a major percentage of the Region's capacity and energy requirements being produced by coal-fired and dual fuel plants in 1984, regulations which call for reduced SO_2 emissions and in turn restrict the operation of existing coal-fired plants could also severely affect the Region's system reliability. Some older coal-fired units, now part of the Region's installed reserve, may have to be retired while the output of other plants may have to be reduced. Additionally, the installation and maintenance of the required new emission control equipment is expected to reduce plant capacity ratings and availability.

Some maintenance and refueling is now being done during peak load periods. These planned maintenance outages, together with unanticipated maintenance outage extensions, forced outages, and the unexpected high load in June, 1984 left MAAC precariously low on reserves for a short period. MAAC was able to meet its reserve objective only by importing over 3,000 MW from adjacent systems and implementing emergency operating procedures. The incident caused MAAC to adjust its summer maintenance scheduling and short range load forecasting practices. The forecast change in load shape after the year 2000 in the MAAC Region from summer to winter peaking is also expected to cause MAAC companies to perform additional periodic planned maintenance during peak periods. Thus, the installed capacity margin objective will have to accommodate those unit outages which cannot be scheduled for non-peak seasons.

TRANSMISSION SYSTEM

The MAAC transmission system is a network of 1,580 miles of 500 kV transmission lines which overlay and interconnect the network of 4,620 miles of 230 kV lines and 170 miles of 345 kV lines. During 1984, 139 MVAR of capacitors were installed on the 230 kV system, bringing the total installed since 1982 to 2,243 MVAR on the 230 kV and 500 kV systems.

During the review period, 155 miles of 500 kV transmission line and 283 miles of 230 kV lines are forecast to be added in the Region. One major MAAC transmission reinforcement project, the Baltimore-Washington 500 kV loop, is currently in progress.

The installation of the Baltimore-Washington 500 kV loop will improve the power system stability in the Baltimore-Washington area and increase the MAAC transfer capability from the adjacent ECAR and SERC Regions by about 650-1,200 MW. This project was originally scheduled to be completed in 1976 but has been delayed until 1991 due to regulatory and judicial involvement. Approximately 75% of the loop is presently in service. The two segments of the loop remaining to be completed within MAAC are the Chalk Point-Calvert Cliffs circuit and the Brighton-Waugh Chapel circuit. A Certificate of Necessity for both of these circuits was received from the Maryland Public Service Commission. However, the Brighton-High Ridge portion of the Brighton-Waugh Chapel circuit still faces regulatory delays due to appeals filed with the Howard County Circuit Court. Until this loop is completed, the Baltimore-Washington area will be exposed to reduced power system stability margins and lower import capability benefits.

With the transmission system as planned, MAAC's emergency import capability from surrounding councils and to sub-areas of MAAC is expected to be adequate through 1994.

OPERATIONS

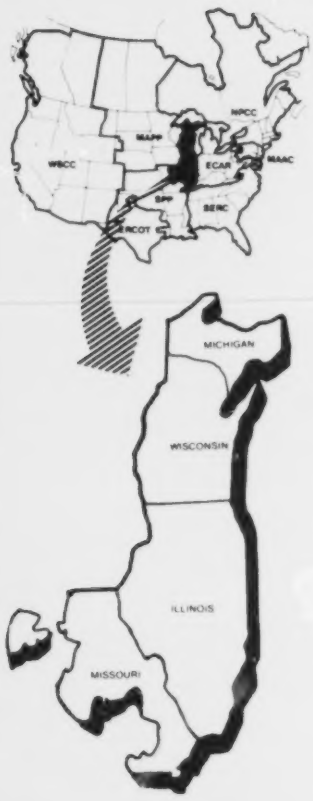
Although accepted reliability standards are maintained, the MAAC regional bulk power system is close to its thermal and reactive power limits for long periods of time due to economy energy imports. The complexity of operating the MAAC system is expected to increase as the members and adjacent systems continue to strive to maximize economies of operation. Currently, MAAC is experiencing substantial parallel path power flows resulting from neighboring systems making economy energy purchases. Coordinated guidelines to address this joint system use are being further developed to ensure that reliability and individual economies are optimized.

MAAC's ability to import economy energy is expected to be fully utilized through the 10-year period. Major west-to-east transmission path utilization averaged 97% in 1984 as it did in 1983. Studies to determine MAAC's ability to import economy energy from neighboring regions and the ability of MAAC and sub-areas of MAAC to import emergency power will continue to be performed on a regular basis. The purpose of these intraregional and interregional studies is to assess the present, near term, and future performance of the bulk power transmission system. System operators are alerted to potential problem areas as they are identified. System development and operating procedures are coordinated with neighboring regions to assure that the reliability of the interconnected transmission system is maintained.

MAAC members now supply all steam and combustion turbine cost and scheduling data to a computerized data base. This information is used by PJM schedulers and dispatchers to improve system economics. Implementation of full on-shift automated scheduling of generating units is presently being phased into daily operation.

The MAAC Region consists of 11 member systems and 5 associates serving over 20 million people over a 48,700 square mile area. The Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey and Maryland, and a small portion of Virginia.

MAIN



1984 STATISTICS			
	Commonwealth Edison	East Missouri	South Central Illinois
Summer Peak — MW	14,572	6,673	6,589
Winter Peak — MW	11,034	4,903	5,448
Annual Energy — GWh	68,309	29,387	32,647
Installed Capability (Summer) — MW	16,504	7,160	9,000
		Wisconsin-Upper Michigan	Total MAIN
Summer Peak — MW		7,352	35,186
Winter Peak — MW		6,420	27,805
Annual Energy — GWh		40,587	170,930
Installed Capability (Summer) — MW		8,944	41,608

A review of the forecast load and the accompanying generation and transmission additions for the next 10 years in MAIN shows that MAIN's adequacy will be satisfactory. While MAIN utilities have the usual concern about their ability to react fast enough in the event load grows faster than forecast, a greater concern is the possibility that some as yet unknown factor might affect MAIN's ability to complete the generating plants now under construction. Almost all of the additional capacity required in MAIN in the next 10 years is under construction. Nuclear plants make up 87% of that construction program. MAIN utilities see no reason why these plants should not be completed on schedule. MAIN's capacity margin would be inadequate by 1992 if none were completed. Since coal is a major fuel in MAIN, the other major concern is the unknown effect of possible actions by U.S. Congress dealing with acid rain.

DEMAND AND ENERGY REQUIREMENTS

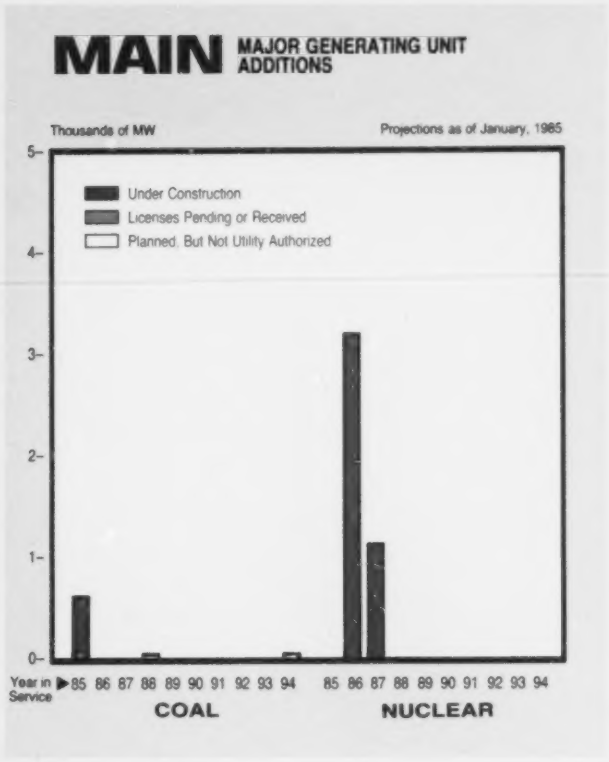
In 1984, MAIN had a summer peak demand that was 1.4% above 1983, and 3.1% above forecast. The high load may have been caused in part by temperature and in part because of the unusual time and circumstances (very late August and early start of schools) of occurrence. In addition, MAIN energy use was 3.0% above 1983 and 3.7% above forecast. MAIN utilities attribute the high energy growth in part to above average temperatures and in part to the economic upturn which began in mid-1983 and continued through most of 1984.

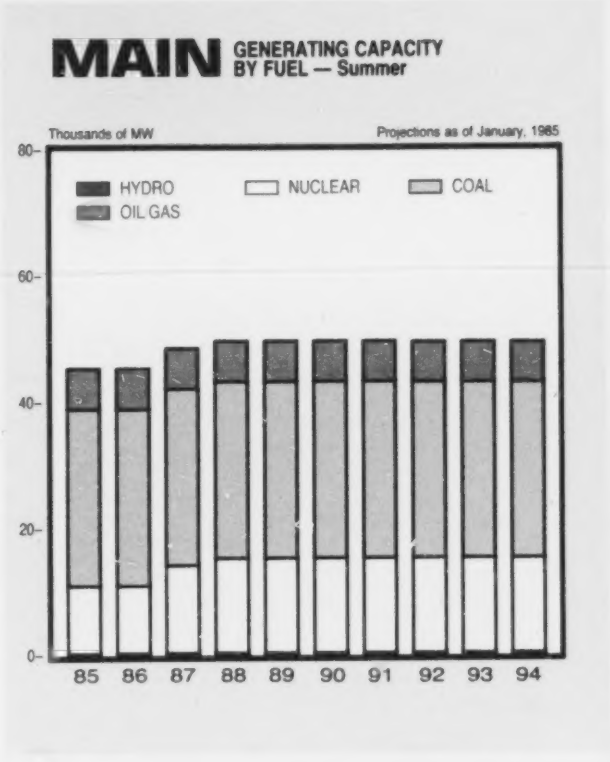
For each of the 11 years preceding 1985, utility forecasters in MAIN successively reduced their forecasts of growth in peak demand for the following 10-year period. In 1985, MAIN utility forecasters are forecasting an average annual growth rate of 1.6% per year for the 10-year period, down from 1.8% last year. The current forecast of 1993 summer peak demand is only slightly less than last year's forecast of 1993.

It is possible that demand might increase above the forecast values if there were a more rapid economic revival than is now expected. MAIN forecasts are intended to have an equal probability of being high or low. However, the effects of higher and those of lower than forecast peak demands are far from equal. The present inability of utilities to site, license and construct new generating capacity in a timely manner results in a greater risk to reliability if current forecasts are too low. If forecasts are too high, planned facilities can be deferred and reliability is not jeopardized.

ADEQUACY OF GENERATION RESOURCES

In the 1985-1987 period, six nuclear units are expected to be placed in commercial operation. These units were committed at the time when growth in electric demand began to slow. While reduced growth rates have served to accommodate some delay in construction schedules, it is in the best economic interest of both the utilities and their customers to bring these units into service and begin to generate energy as soon as possible.





Therefore, generating capacity margins in MAIN will be above the minimum levels required for reliability for several years after these large units are completed.

Present analysis suggests that MAIN members should maintain an installed generating capacity level of at least 15 to 20% above peak load. (This is equivalent to a capacity margin of 13 to 17%.) Margins will be comfortable during the 10-year period with demands as forecast and capacity as planned. This situation offers several advantages. With ample margins, economical replacement power within the system itself or from others in the Region will be more readily available. Because returning a unit to service after an outage is not as critical as it is when margins are closer to minimum levels, maintenance can be performed more economically. Also, in most MAIN systems, peak load and energy requirements can be met by using reliable low-cost coal and nuclear generation. The availability of low-cost generation also provides opportunities for sales to other areas to displace oil and gas-fired generation.

No major units are planned for completion in MAIN during the 1988 to 1994 period. Nevertheless, generation capacity in 1994 will be able to support the peak demand forecast for that year.

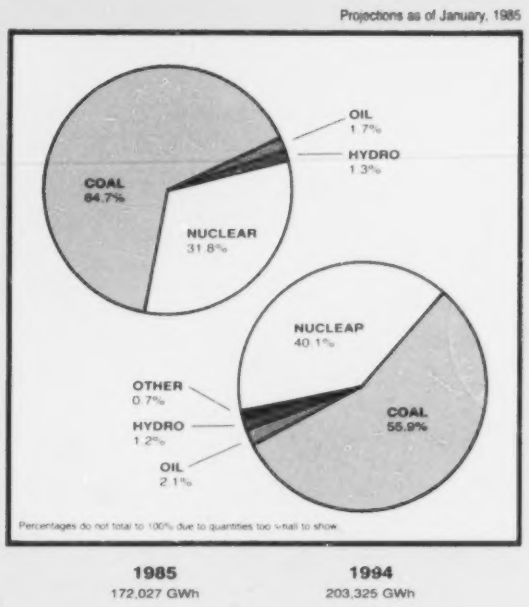
With power plant construction requiring a lead time of 8 to 14 years, a slight increase or decrease in forecast demands could result in premature or belated installation of generating units. A utility's ability to cope with relatively small, unexpected increases in the rate of growth is severely limited by the long lead times of new generating capacity. Even relatively short lead time capacity such as combustion turbines can now take as much as 5 years to site and construct. Adequacy could be seriously reduced if significant economic growth not now forecast occurs by the late 1980's or early 1990's.

MAJOR FACTORS INFLUENCING ADEQUACY

The most critical factor influencing adequacy in MAIN is the ability to complete the 6 nuclear plants which present 87% of the capacity addition program. In 1994, nuclear plants will provide 40% of MAIN's energy. One nuclear unit canceled would not result in a reliability problem until after 1994. If for some reason, however, none of the units under construction (and which owners at this time expect to finish) were completed, there could be inadequate capacity as early as 1992.

Since coal is the major fuel in MAIN, possible U.S. Congressional actions dealing with acid rain may have a major effect on MAIN utilities. In addition to the concern for the cost of meeting possible requirements of reduced SO_2 emissions, MAIN reliability can be adversely affected. The output of existing coal units

MAIN ELECTRIC GENERATION BY FUEL



might be reduced 3 to 5% and it might not be possible or economic to retrofit flue gas desulfurization equipment on older units, thus causing premature retirement.

TRANSMISSION

Economy transactions among MAIN utilities and between utilities in MAIN and surrounding regions have increased over the years. As a result, the present interconnected transmission system is being more heavily loaded a higher percentage of the time. This increases the vulnerability to major interruptions. Reliability criteria are still being met, but transmission margins are less than they have been. Delay of committed transmission projects and deferral of other projects for financial reasons also increase this vulnerability.

With the increased demands being placed on the transmission system, it is important that right-of-way and certification problems be resolved promptly so new facilities can be brought into service without unnecessary delays.

OPERATIONS

Utilities are countering the increased risk being caused by increased economy transfers and more extensive loading of the transmission system by providing additional operational capability and increased operator preparedness. MAIN is now in the process of reevaluating its communication system in anticipation of the need to provide for a higher level of monitoring, both within MAIN and with adjacent regions. In addition, work is underway to improve control centers to provide operators with more and better information on the current state of the power system, and to provide continued and more extensive operator training.

The Mid-America Interpool Network (MAIN) consists of 12 regular member systems and 1 associate member. MAIN is a summer peaking region covering Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin and most of the Upper Peninsula of Michigan.

For reporting purposes, MAIN is divided into four subregions: Commonwealth Edison Company (CECO), the balance of Illinois (SCIL), Eastern Missouri (EMO), and the Wisconsin-Upper Michigan area (WIUM).

MAPP

1984 STATISTICS		
	MAPP — U.S.	MAPP — Canada
Summer Peak — MW	20,666	4,087
Winter Peak — MW	18,989	5,081
Annual Energy — GWh	105,378	25,665
Installed Capability — MW	28,161	6,422

Capacity margins for the 1985-1993 period will meet MAPP reliability criteria. However, the margin drops slightly below the minimum criteria level in 1994. It is necessary that committed capacity be completed on schedule and additional commitments for resources be made in order to increase the 1994 capacity margin.

Transmission capability within MAPP is capable of supplying firm power requirements, with enough transfer capability for scheduling significant emergency and economy energy.

DEMAND AND ENERGY PROJECTIONS

The MAPP demand and energy forecasts are the sum of the individual MAPP member forecasts. The United States portion of the MAPP Region is summer peaking and had a non-coincident summer peak of 20,666 MW in 1984. This demand was 0.6% below the 1983 peak and 4% below the forecast. Energy was 2.6% above the 1983 actual amount. The Canadian provinces which are associated with MAPP are winter peaking and had a non-coincident peak demand of 5,081 MW in the 1984-85 winter season, nearly 5.3% above the 1983-84 winter peak.

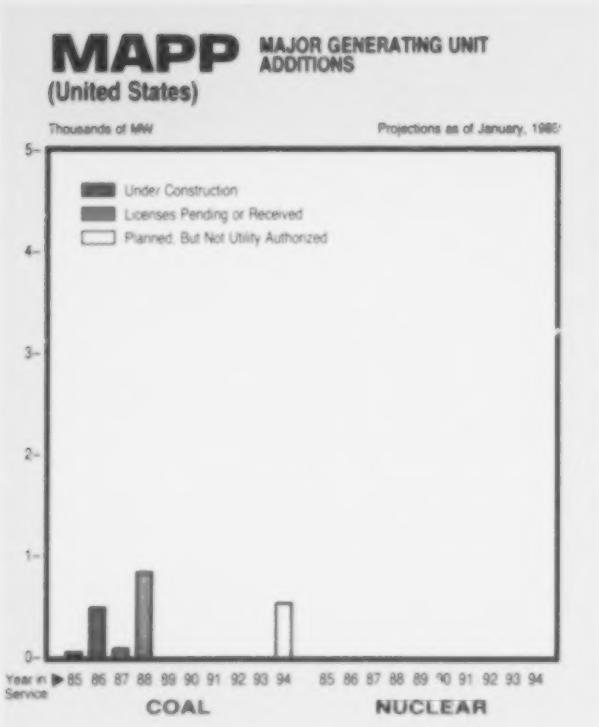
Summer peak demand and annual energy of the MAPP Participants are estimated to increase at average annual rates of 2.2% and 2.5%, respectively, in the 1985-1994 period. These projections are somewhat less than the previous year's forecast of 2.4% and 2.9%, and result in the 1993 peak demand projection being 2.8% (745 MW) less than was forecast last year. Reasons cited for the lowered forecast within MAPP are the depressed farm economy and the decrease in the taconite industry's electric service needs. Additionally, more of the utilities within MAPP are pursuing load management programs with more than 1,500 MW of load management planned by the early 1990's. Portions of this planned load management are excluded from the peak forecast of several systems.

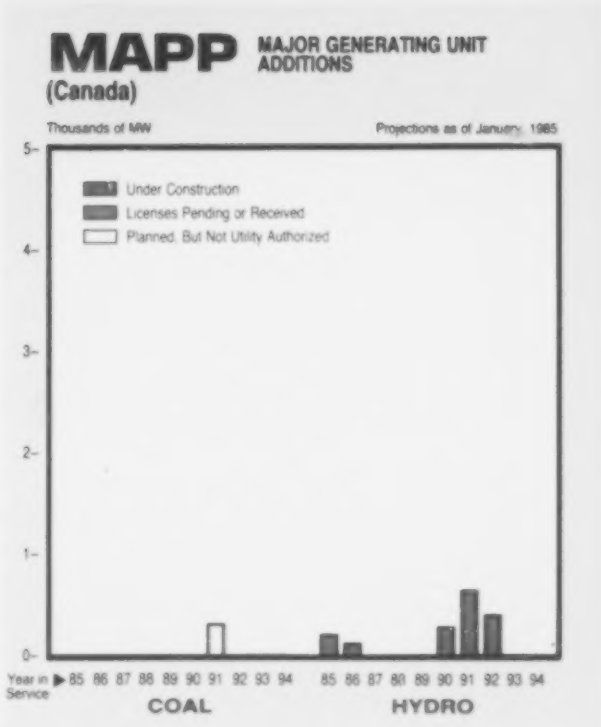
RESOURCE ADDITIONS

A 460 MW coal-fired unit and a 50 MW hydro unit were placed in service during 1984. Generation additions committed or proposed by MAPP Participants for the 1985-1994 period include 3 large fossil units totaling 1,650 MW. Only small amounts of generation from other renewable resources, such as wind, solar, and biomass, are anticipated in this 10-year period. Smaller unit additions, unit retirements, upgrades, and/or derates which will take place during this period have the net effect of reducing capacity by 150 MW. The capacity mix for 1985 and forecast for 1994 is shown in the following tabulation, rounded to the nearest 100 MW:

MAPP
Capacity Mix (U.S. only)

	1985		1994	
	MW	%	MW	%
Coal	18,500	65	20,300	68
Nuclear	3,700	13	3,700	12
Renewable Resources: Hydro, Wood, and Refuse	3,000	10	2,800	9
Gas/Oil Peaking	3,400	12	3,300	11
TOTAL	28,600	100	30,100	100





Cogeneration facilities included in the above capacity account for 21 MW in 1985 and 37 MW in 1994. Although not included in the above, an additional 57 MW of cogeneration capacity is anticipated to be in service by 1994.

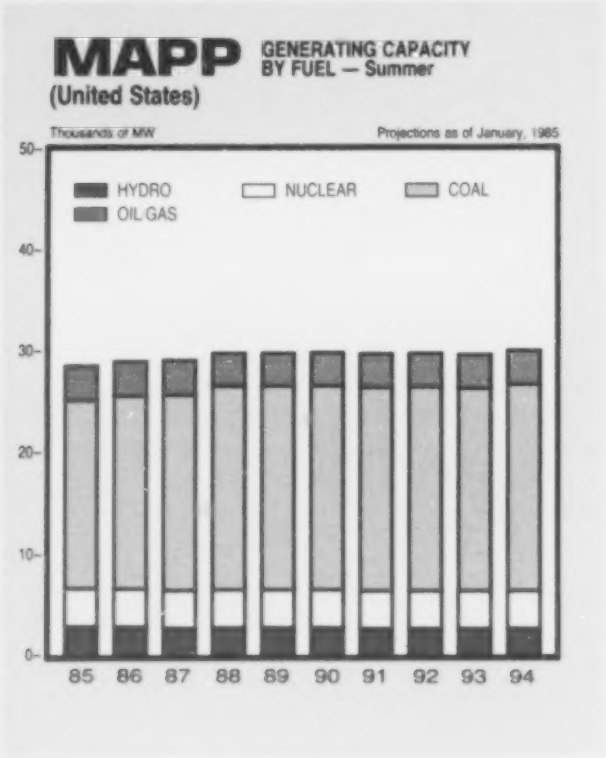
The Canadian Provinces associated with MAPP will add 252 MW of hydro capacity by 1986, and an additional 1,200 MW of hydro capacity by 1993. Scheduled are one 210 MW coal-fired unit for service in 1992 and 450 MW of combustion turbines for service during the period 1988 to 1994. The capacity for the Provinces will increase from 6,379 MW in 1985 to 8,491 MW by the end of 1994.

GENERATION ADEQUACY

Reliability studies and experience of systems in the MAPP Region indicate that each Participant should maintain a capacity level at least 15% above its annual peak load to provide the same level of reliability of power supply experienced in the 1970's. (This is equivalent to a 13% minimum capacity margin.) The 1970's was a period of demonstrated reliability within the Region.

Historically, within MAPP there has been a diversity of about 6% in annual peak demands. This suggests that the MAPP Region should maintain a capacity margin of about 18%, based on the Region's coincident peak demand. Under a new schedule, interruptible loads which are properly certified may remain uninterrupted on system peak, provided an energy supply can be found from other energy suppliers within the Region. Under this plan, the interruptible load component for which an energy supply is purchased, will not be counted in the utility capacity margin calculations.

The MAPP reliability criterion requires a minimum Regional reserve margin of 15%. With the committed unit additions, reserve margins for the 1985-1993 period will range from 34% in 1985 to 17% in 1993, and the MAPP reliability criteria will be met through 1993. However, the reserve margin for 1994 drops to 14%, slightly below the minimum reliability criteria. It is necessary that the committed capacity be completed on schedule and additional commitments for resources be made in order to meet the reliability criteria. A 400 MW unit proposed for 1994 would satisfy this additional need. It would be most helpful if generating unit construction lead time could be reduced. The uncertainty associated with construction needs could be greatly reduced if lead time were five or six years instead of the current ten to twelve years.

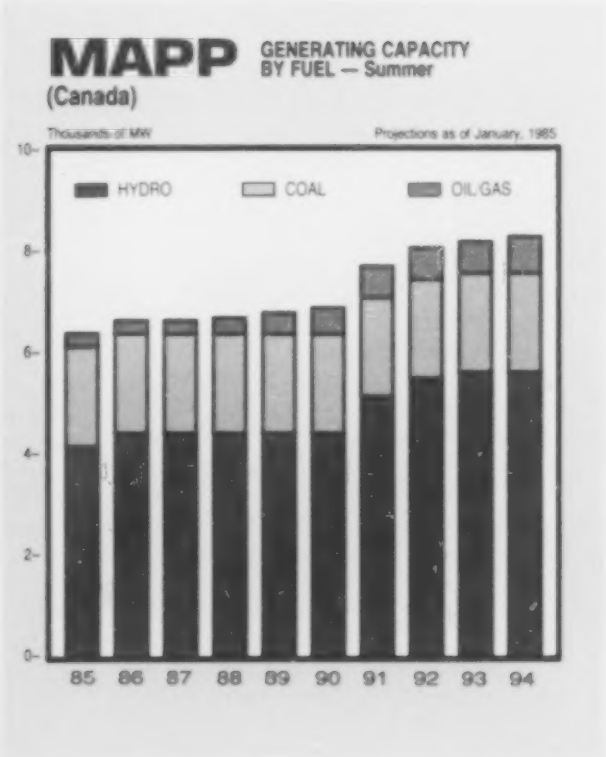


Spent fuel storage for 7 nuclear plants totaling 3,700 MW of the current base load capacity within MAPP continues to be of concern for the early 1990's. Storage capacity at the plant sites is sufficient to allow full core discharge only until the early 1990's. Vitally needed are Federal AFR (Away From Reactors) facilities.

Implementation of a program for storage of spent nuclear waste is necessary to avoid reduction in operation of the nuclear units. Such a reduction would increase the cost of electricity to consumers, increase oil consumption, and reduce the reliability of power supply. The Nuclear Waste Policy Act of 1982 sets a timetable for construction of the first two nuclear waste repositories; however, there is concern within MAPP that the time schedule will not be met unless progress is substantially increased.

Legislative efforts to reduce sulfur dioxide emission from power plants in an attempt to mitigate acid rain are of continuing concern to MAPP members. Addition of emission-control equipment will reduce the power available from the units on which it is installed, will increase maintenance time, and could contribute to early retirement of older units because of the high cost of installation and operation of a retrofit.

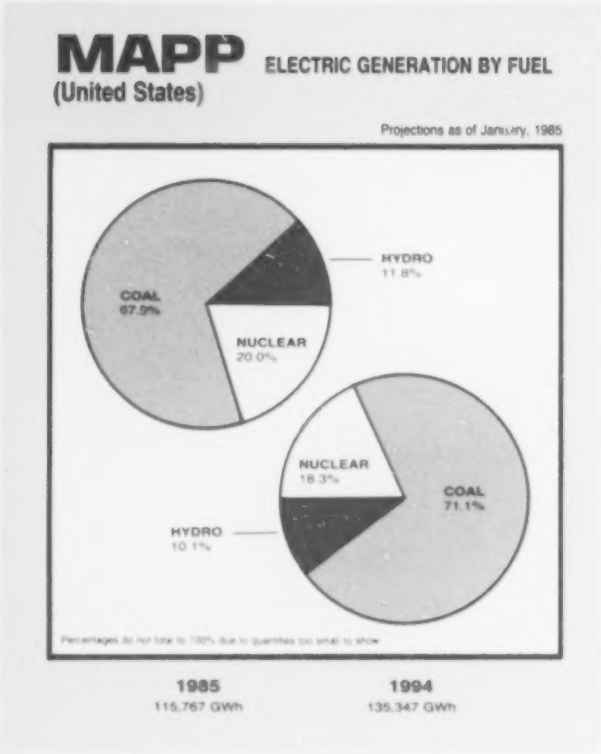
TRANSMISSION ISSUES

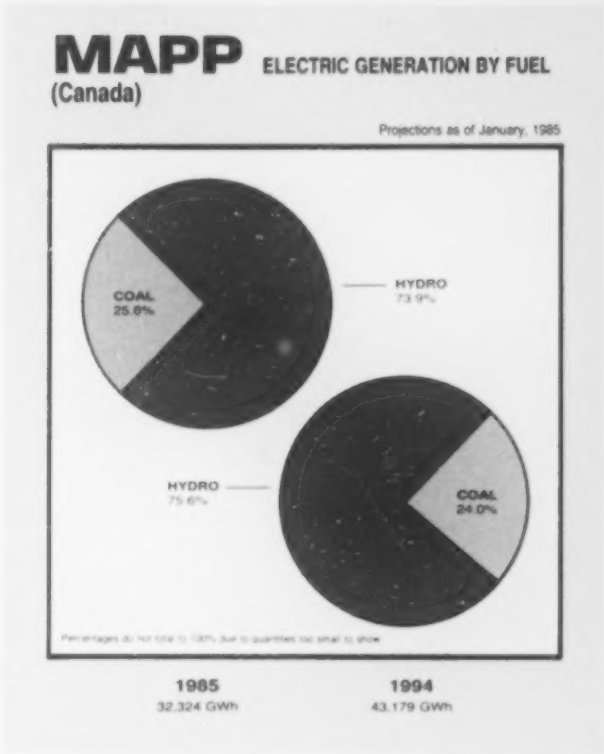


The MAPP utilities have 18,278 miles of transmission 230 kV and above in service and plan to build 2,518 miles of transmission 230 kV and above by the end of 1994. The MAPP transmission network is capable of supplying firm power requirements, with enough transfer capability for scheduling significant amounts of emergency and economy energy. In general, intraregional transfer capabilities are adequate for reliability.

The Manitoba, North and South Dakota, and Nebraska 500 kV line (MANDAN Project) was terminated in March 1985. This line would have provided for seasonal diversity capacity exchanges between MAPP Participants. Inability to secure cost-sharing arrangements with participating utilities and a stalemate in negotiations over electricity price led to the project termination.

MAPP recently completed revised guidelines for stability control of the northern MAPP system. The new procedure enables MAPP to operate with higher export limits when certain lines or generators are out of service. The net effect is that the transmission system can be more fully utilized in delivering power from North Dakota while still meeting reliability criteria.





MAPP has developed a yardstick for members to use in evaluating their transmission outages. One system which used the evaluation technique found an unusually high incidence of outages on a line. Investigation showed that the line was not adequately grounded. This caused voltages to build and current to travel down the pole, drying the surrounding soil and ground cover. Fires often resulted. Grounding was improved and substantial savings have resulted.

REGIONAL TRANSMISSION AND GENERATION STUDIES

Manitoba Hydro and utilities in Minnesota and Wisconsin are studying the feasibility of supplying hydro power to Minnesota and Wisconsin. The Western Area Power Administration is also evaluating the possibility of bringing hydro power from Manitoba into the Dakotas for delivery to its customers throughout the MAPP area. Both of these studies involve the analysis of transmission requirements and economics of advancing construction of hydro facilities on the Nelson River in the early 1990's. The U.S. Corps of Engineers is continuing a study of installing a pumped hydro facility in South Dakota near the Missouri River. Total capacity of this facility, identified as Gregory County, is approximately 2,300 MW. It is anticipated that this study will be completed in late 1985.

OPERATIONS

Operation of the MAPP power supply system is becoming more complex. The large amount of economy energy transfers which have loaded the transmission system differently than was anticipated at the time of design, coupled with the operating constraint of large base load units' inflexibility (particularly during light load periods), have made the operator's job more challenging.

The MAPP utilities have several programs and procedures that provide the operator with support in completing his job. Included are an extensive MAPP System Operator Training program, established emergency replacement procedures, transmission line loading relief procedures, and a procedure to optimize economy transactions. In addition, MAPP has embarked on a project to modernize and expand its computerized communications system to improve data collection, modeling, and communications among the Participants and with neighboring regions.

The Procedure to Optimize Economy Transactions (POET) has brought pool-wide savings of $3 million during 1984. POET assists MAPP Participants in arranging economy transactions each hour, thereby supplementing normal economy interchanges among

pool systems. Another procedure, the Before-the-Fact Cost Procedure, has been instituted on a trial basis to assist Participants in making decisions regarding which units should be run each day to further maximize economy of operations within reliability limits. Additionally, MAPP is exploring the feasibility of pool-wide unit commitment and economic dispatch.

The Mid-continent Area Power Pool (MAPP) membership includes 44 systems. There are 27 Participants consisting of 11 investor-owned systems, 8 G&T cooperatives, 3 public power districts, 4 municipal systems, and 1 federal agency. The Associate Participants consist of 2 Canadian Crown Corporations, 14 municipals, and 1 investor-owned system. The MAPP Region covers all of the states of Iowa, Minnesota, Nebraska, and North Dakota; portions of the states of Illinois, Michigan, Montana, South Dakota, and Wisconsin; and the provinces of Manitoba and Saskatchewan. Total population in the Region is about 16 million.

NPCC

1984 STATISTICS*				
	New York	New England		Total NPCC — U.S.
Summer Peak — MW	21,870	16,274		38,144
Winter Peak — MW	20,381	16,940		37,321
Annual Energy — GWh	124,338	93,117		217,455
Installed Capability (Summer) — MW	30,803	20,509		51,312
	New Brunswick	Ontario	Québec	Total NPCC — Canada
Summer Peak — MW	1,282	15,787	12,030	29,099
Winter Peak — MW	1,806	19,257	21,710	42,773
Annual Energy — GWh	9,837	112,293	105,885	228,015
Installed Capability (Summer) — MW	2,928	25,357	23,003	51,288

Unacceptable reliability will be encountered in New York and New England, starting in the 1990's, unless present regulatory and financial impediments to committing new generating resources are removed.

PEAK DEMAND AND ENERGY

Electricity consumption in NPCC was higher in 1984 than in 1983. Total energy for load grew by 2.7% among NPCC systems in the United States, and by 6.1% among Canadian NPCC systems. Energy and peak demands generally exceeded forecasts.

Forecasts for the last year common to both this year's and last year's forecasts, 1993, show increases for peak demand and energy in both the United States and Canada:

NPCC
1993 Peak Demand and Energy

This Year's Forecast as a Percentage of Last Year's Forecast

	NPCC/U.S.	NPCC/Canada
1993 Peak Demand	101.5	105.3
1993 Annual Energy	100.1	105.1

*Data for Nova Scotia Power Corporation, which recently became a member of NPCC, are not included in the exhibits of this report.

Forecast growth rates from 1985 through 1994 are about the same this year as last

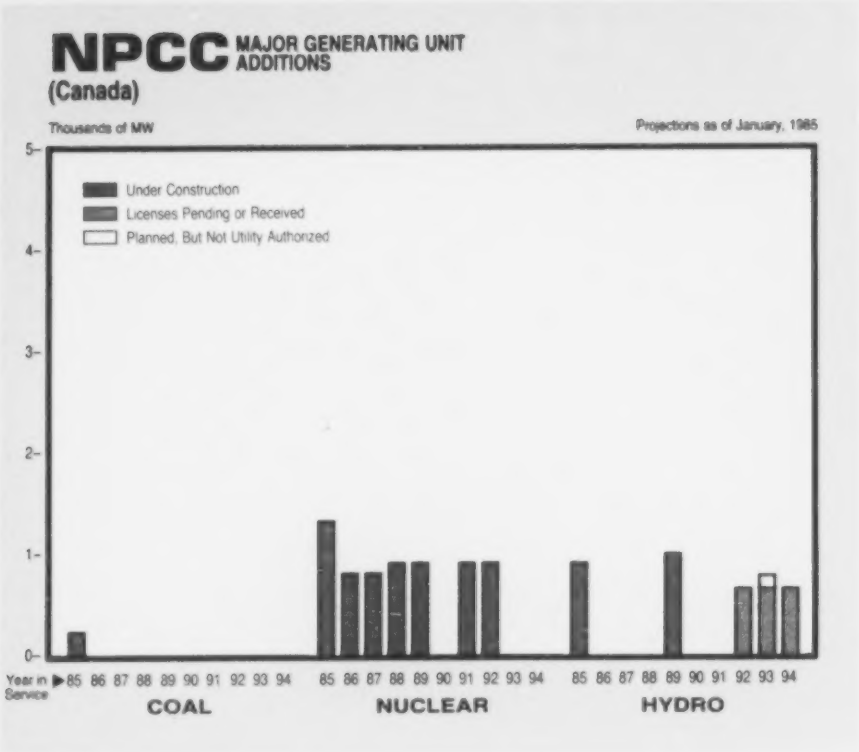
NPCC
Peak Demand and Energy

Forecast Average Annual Increase over Next 10 Years — %/yr

	NPCC/U.S.	NPCC/Canada
Peak Demand — 1985 Forecast	1.6	3.0
Peak Demand — 1984 Forecast	1.7	3.0
Annual Energy — 1985 Forecast	1.7	3.1
Annual Energy — 1984 Forecast	1.9	2.9

GENERATION RESOURCES

The base generation expansion for the New England Power Pool (NEPOOL) anticipates the completion of the Seabrook 1 and Millstone 3 nuclear units (2,300 MW), and the addition of 1,900 MW of cogeneration and small power facilities. In addition, 1,050 MW of load management is expected by the year



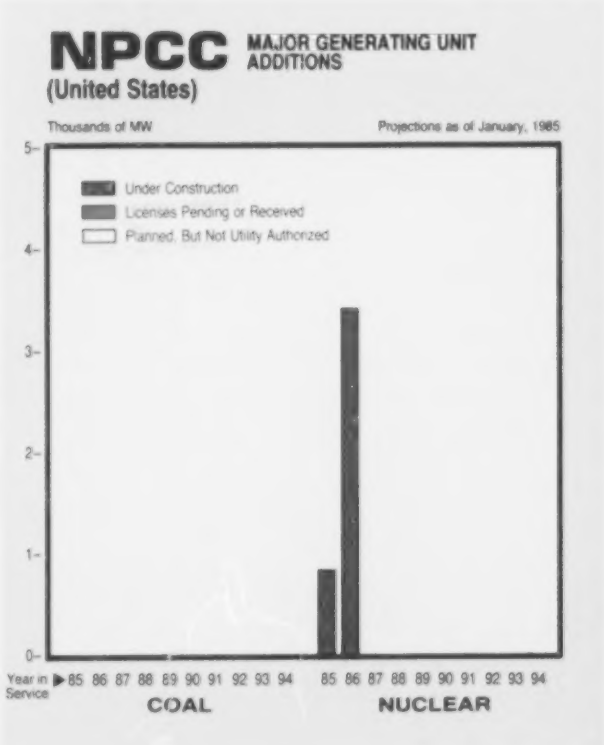
during the 1990's. In addition, oil-to-coal conversions will not equal earlier projections due to a combination of environmental issues and reduced economic incentive.

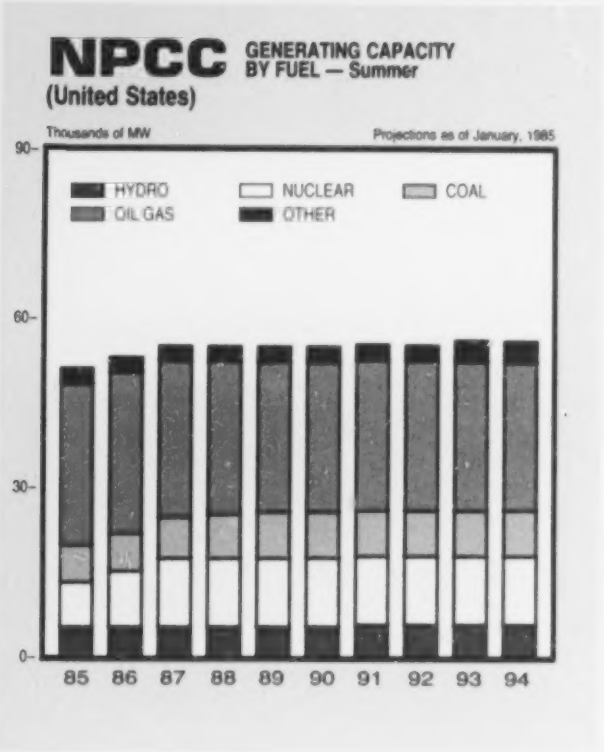
Ontario Hydro's committed generation capacity additions from January 1985 to the end of 1993 consist of 8 nuclear units (1 Pickering B unit, 3 Bruce B units and 4 Darlington units) totaling 6,401 MW, one 206 MW coal-fueled unit and 52 MW oil-fueled combustion turbines. No difficulties are anticipated in meeting target unit in-service dates and the program is adequate to meet Ontario Hydro's system requirements until the mid to late 1990's.

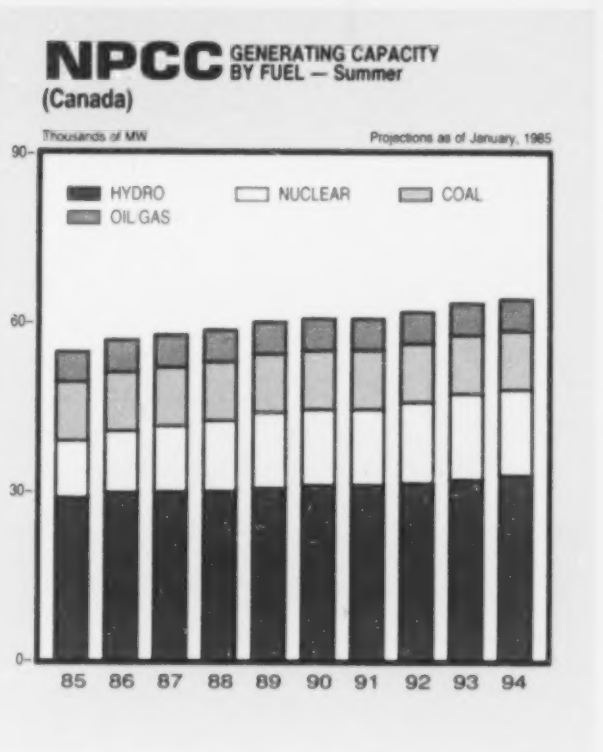
For Hydro-Québec, the generating capacity of existing facilities should be able to satisfy power needs until 1990 2000. The requirements for additional capacity (beyond present commitments) in New England in the 1990's will be in the order of 2,400 MW.

To meet capacity needs in the New York Power Pool (NYPP), several new plants are either planned or have been recently put into operation. The Somerset coal-fired unit (625 MW) in upstate New York was placed in service in 1984. The Shoreham nuclear unit (809 MW) on Long Island is now scheduled for service in October 1985, and fueling has been completed. However, Shoreham remains the focus of considerable opposition and its ultimate operation is still in doubt. The Nine Mile Point 2 nuclear unit (1,080 MW) in upstate New York is scheduled for service by October 1986 and is now about 90% complete. The Prattsville pumped storage hydro project (1,000 MW) was denied a license by the New York State Department of Environmental Conservation (DEC); Prattsville's scheduled in-service date has been delayed to May 1993 and discussions are being held with the DEC to resolve their concerns. A 300 MW hydro expansion at the existing Niagara project is planned for March 1991. NYPP expects increases in the use of renewable and alternate technologies of about 240 MW over the next 10 years. Given the uncertainties inherent in load forecasts and system capacity conditions, NYPP is concerned about the adequacy of installed generating capacity in the mid to late 1990's.

Increased dependence on oil is anticipated in both New England and New York as capacity margins decline







and energy needs until 1997. However, to increase flexibility and to increase the possibility of winter energy sales, an additional 980 MW of hydroelectric generating capacity will be commissioned at the Manic 5 site in 1989. This addition will be followed by the commissioning of 1,900 MW of additional capacity at the LG 2 site (LG 2 A) during the 1992-94 period. Between 1994 and 2001, another 3,300 MW of peaking capacity will be required and alternatives are now under study. La Grande Phase 2 development (2,500 MW and 15 million MWh) should be sufficient to meet additional energy requirements until 2004.

Studies undertaken by Maritime Nuclear on the application of a second nuclear unit at the Point LePreau Generating Station examined the economic viability of the construction of the unit to, in a large part, serve the markets in the northeastern U.S. on a long-term basis. In view of the requirement for additional energy starting in 1992/93, it might be economical for New Brunswick Power to purchase a portion of the output of such a second unit. Considering the reserve generating capacity required to provide allowance for generating equipment to be shut down for maintenance and/or equipment failure, NB Power has sufficient generation installed to meet its capacity requirements to the year 1994.

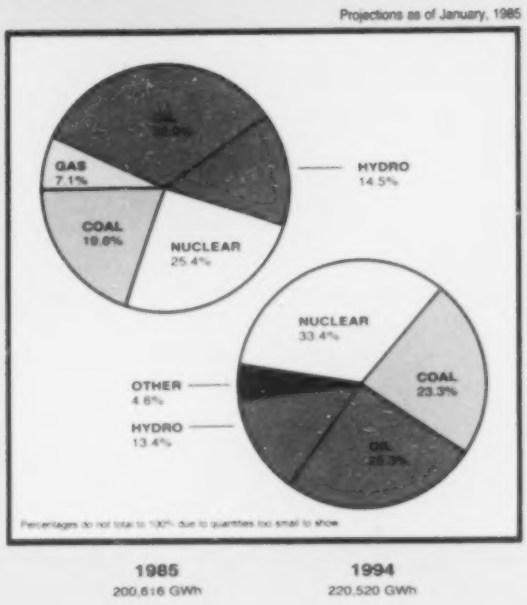
Nova Scotia Power Corporation, which became a member of NPCC in 1985, is nearing a decision for the addition of up to 300 MW of coal-fired capacity required in 1991/92.

ENVIRONMENTAL CONSIDERATIONS

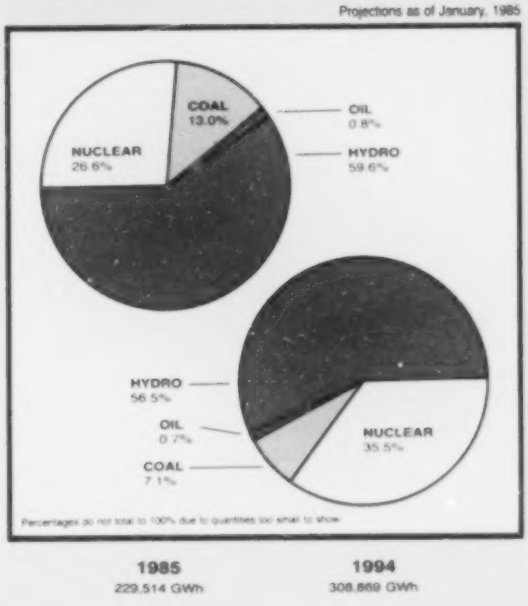
New York State recently enacted acid rain legislation. The Department of Environmental Conservation is now developing implementation regulations; as a result, changes which will be required and concomitant costs are still uncertain. It is believed that whatever conformance program is finally implemented will go into effect in 1988.

For Ontario Hydro, current acid gas emission regulations are not expected to limit the energy production from fossil-fueled generation up to the mid to late 1990's, as a result of the energy contributions from hydraulic and nuclear generating sources and burning of low sulphur coals. Investigations of emission control technologies are continuing, to ensure that Ontario Hydro remains within emission limits when the coal burns start to increase in the mid 1990's. Up to 1994, nuclear generation additions on the system will reduce the energy from coal-fueled sources and acid gas emissions will be correspondingly reduced. It is expected that generation from oil- or gas-fueled units will be negligible.

NPCC ELECTRIC GENERATION BY FUEL (United States)



NPCC ELECTRIC GENERATION BY FUEL (Canada)



TRANSMISSION

An extensive study program is in process under the direction of a Steering Committee composed of representatives from NYPP, NEPOOL, Hydro-Québec and New Brunswick Power to determine the system configuration and the operating procedures necessary to make the proposed HQ/NEPOOL 2,000 MW interconnection function in a reliable manner. This HVDC interconnection between Des Cantons in Québec and Comerford in northern New Hampshire, scheduled for July 1986, will provide a 690 MW transfer capability between Hydro-Québec and NEPOOL in its initial phase, to be increased to 2,000 MW in 1990. The studies will be reviewed by both NPCC and the other systems within the MAAC-ECAR-NPCC (MEN) area, and, to this end, a MEN 1990 study is now in progress.

Another HVDC interconnection between Québec and Vermont is scheduled for September 1985. The interconnection will consist of a 200 MW back-to-back HVDC station located at Highgate, Vermont and will be linked to Hydro-Québec's system by an ac line.

NEPOOL and New Brunswick Power are studying the addition of a second 345 kV tie line for possible completion in the late 1980's or early 1990's. Such a line would permit additional energy from Hydro-Québec to be delivered to New England as well as coal-fired generation from New Brunswick and Nova Scotia. In addition, the second tie line would facilitate the purchase of an entitlement in the Point LePreau plant when needed.

A fifth 735 kV ac line from the James Bay area to Québec City was commissioned early in 1985. The additional capacity at La Grande Phase 2 requires the commissioning of a sixth James Bay transmission line in 1992. However, among the various alternatives possible to satisfy the requirements related to the agreement with NEPOOL, the isolation of some generating units at the LG-2 complex and the transmission of energy from these units by a dc line to the American border has been shown to be the best solution. For this reason, the sixth line will be dc and its commissioning will coincide with the beginning of the NEPOOL contract in 1990.

A second interconnection between Québec and New Brunswick, consisting of a 350 MW back-to-back HVDC tie at Madawaska, Québec, as well as an additional 200 MW of load directly connected to the Hydro-Québec system, will effectively double the transfer capability from Québec to New Brunswick when it is completed in 1985. The existing Eel River HVDC tie has a capacity of 350 MW, which is complemented by approximately 175 MW of load directly connected to the Hydro-Québec system.

Large power transfers to displace oil continue to characterize the NYPP transmission system. Import capability from Hydro-Québec has been increased with the installation of a 1,000 MW back-to-back HVDC facility near Montreal.

The 200-mile 345 kV Marcy South reinforcement between central and southeastern New York was recently approved by the New York State Public Service Commission (PSC). The Commission also approved this as a predominantly double circuit reinforcement. Some portions are scheduled for service by January 1987, while more westerly segments will be delayed until January 1988 because of route changes ordered by the PSC. In concert with these transmission additions, NYPP expects to add approximately 2,600 MVAR of voltage support, including 2 static VAR compensators.

Plans for new 500 kV transmission in Ontario, which would complete incorporation of the Bruce nuclear complex (on Lake Huron) into the Ontario Hydro transmission network, suffered a serious set-back in the last year. This transmission is also required to provide a reliable supply for forecast load growth in the southwestern portion of the Province and maintain transfer capability to the international border with Michigan. A "plan stage" approval for this transmission had been obtained in 1982 from the provincial government and route stage studies to locate the lines were nearing completion. However, in June 1984, the Supreme Court of Ontario agreed with two citizens' groups and several municipalities that inadequate notice had been given by the Board appointed by the Province to hear matters relating to the need and system plan. As a result, the Court quashed the plan stage approval. This will delay the in-service date of these facilities by about 1.5 years minimum.

The Court also quashed plan stage hearings held in 1982 with respect to 500 kV lines required in the eastern part of the province to supply forecast load growth. Route stage work had been proceeding satisfactorily and government approval was expected before the end of the year. The first of these lines was needed last January to meet reliability criteria based on loss of a critical line with another line already out of service. Because of earlier approval delays, the first line is not scheduled for service before late 1989. This latest set-back in the approval process is not expected to delay the in-service date significantly.

OPERATIONS

Responsibility for the operation of the NPCC system rests with the two U.S. power pools and the individual Canadian systems. Within the power pools, a hierarchical system of control is used. In New York, this proceeds directly from the NYPP control center to the member systems; in NEPOOL, control is from the New England Power Exchange dispatch center to satellite centers, and thence to the individual member utilities. Each Canadian system operates its own control center.

Communication systems, both voice and telecommunications, are maintained among the subregional control centers of NPCC, and with neighboring systems. A computer-to-computer communication system is presently in service; Ontario Hydro will join the system, which also includes NYPP, NEPOOL and PJM, by the end of 1985. Multi-system real time monitoring greatly enhances the ability of system operators to monitor and control their collective systems, and particularly the parallel path flow problems caused by multiple power transactions.

The communication systems noted above are important during emergency conditions, as well as at times of normal operation. NPCC has also established "Procedures for Emergency Operation" to facilitate mutual assistance and coordination within NPCC in an emergency or during conditions which could lead to an emergency. The NPCC has a formal training program with sessions conducted semiannually. The Council also has a coordinated manual and automatic load shedding program.

A major project undertaken in 1985 among the NPCC Areas and PJM was the initiation of ongoing testing of Shared Activation of Reserve (SAR), designed to allow any one Area to recover more quickly from a contingency by the shared activation among the Areas of ten minute reserve. It is expected that, based on study results, a decision will be made by the end of 1985 to formalize the concept.

The most significant problem in operations continues to be the heavy loading of the bulk power transmission system at or close to transfer limits a large percentage of the time. It is expected that these heavy loadings will continue in the foreseeable future.

The Northeast Power Coordinating Council (NPCC) represents 22 investor and publicly-owned utility systems serving about 43 million people in the northeastern United States and eastern Canada. NPCC is divided into 6 Areas, each an operating and planning entity. In the United States, NPCC members participate in either the New England Power Pool (NEPOOL) or the New York Power Pool (NYPP). In Canada, the 4 members — Ontario Hydro, Hydro-Québec, New Brunswick Power and newly-joined Nova Scotia Power — are province-wide systems and make up 3 of NPCC's 5 Areas. Together, the NPCC Members supply about 98 percent of all the electricity in the NPCC Region.

SERC

1984 STATISTICS					
	Florida	Southern	TVA	Virginia — Carolinas	Total SERC
Summer Peak — MW	20,280	23,174	18,504	31,442	93,400
Winter Peak ('84/'85) — MW	26,298	22,124	22,740	35,675	106,837
Annual Energy — GWh	103,731	120,102	110,839	168,243	502,915
Installed Capability (Summer) — MW	26,265	31,454	29,847	39,996	127,562

SERC will have adequate capacity margins and projects no reliability problems through 1994 if the currently planned generating capacity and transmission lines are completed as scheduled. Some SERC subregions are very concerned about the potential impacts of long-term and short-term economy transactions, unit aging, mothballing of units, and load restoration preparedness. Even though substantial oil-fired capacity has been converted to coal, and coal-by-wire transfers continue into the 1990's, one subregion foresees the continued need for large quantities of oil through the review period.

DEMAND AND ENERGY

The diverse geographic and socioeconomic conditions within the 345,650 square miles of the SERC Region are reflected in the summer peak load forecasts for the subregions ranging from 2.1% to 3.1% per year for the 10-year period. The VACAR and Southern subregions are summer peaking and the TVA and Florida subregions are winter peaking.

The record-setting cold temperatures of January 21 and 22, 1985 resulted in new all-time peak demands in 3 of the 4 subregions. SERC subregions exceeded the aggregate winter 1984/85 forecast by an average of over 12%. The SERC regional demand of January 1985 met the currently projected winter peak demand forecast for the winter of 1990/91.

SERC
Winter 1984/85

	Forecast Peak Demand (MW)	Actual Peak Demand (MW)	Increase over Forecast (%)
Florida	22,905	26,298	14.8
Southern	19,004	22,124	16.4
TVA	21,975*	22,740	3.5*
VACAR	31,109	35,675	14.7
SERC	94,993*	106,837	12.5*

*Based on TVA high band forecast.

Three subregions of SERC are forecasting somewhat lower peak demand growth rates than those reported in 1984. Florida is the only SERC subregion currently reporting higher expected growth rates.

SERC
Projected Annual Growth Rate (%/yr)
1985-1994

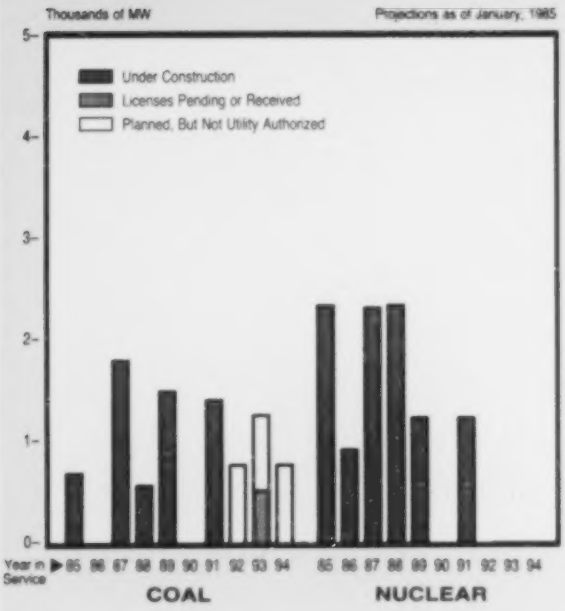
Subregion	Summer Peak Demand	Winter Peak Demand	Annual Energy
Florida	3.1	2.4	3.1
Southern	2.6	2.3	2.4
TVA	2.6**	2.1*	2.2*
VACAR	2.1	2.2	2.8
SERC	2.5**	2.2*	2.6*

*Based on TVA high band forecast.
**Based on TVA mid-band forecast.

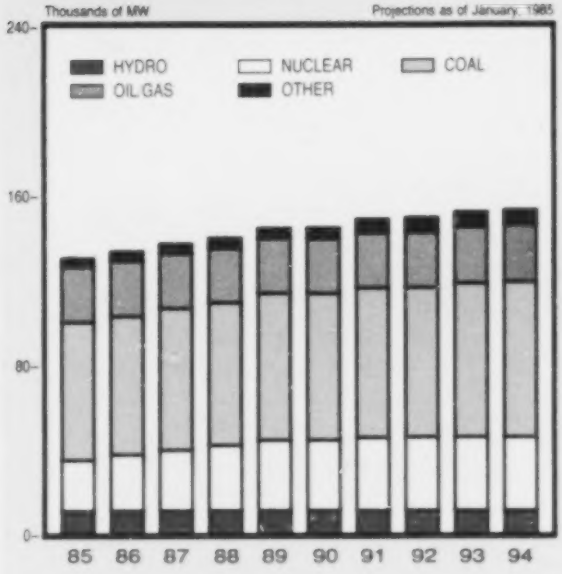
GENERATION CAPACITY AND ADEQUACY

Capacity additions for the 1985-1994 period include 9,006 MW in 16 coal-fired units, 10,504 MW in 9 nuclear units, 3,408 MW in 17 pumped-storage units, 706 MW in 15 hydro units, and 216 MW in 2 combined cycle units. No units are committed for service after 1994. During the past year, several changes have been made in the planned capacity additions for the Region. One coal unit (600 MW) has been deferred beyond this reporting period; 3 pumped-storage hydro units (848 MW) have been deferred for 2 years; and 4 nuclear units (5,036 MW) which had been previously deferred out of the period have been canceled. The cancellations and deferrals are attributed to such factors as lower load forecasts, changes in regulatory requirements, uncertainty regarding future regulatory treatment, increased conservation and load management, addition

SERC MAJOR GENERATING UNIT ADDITIONS



SERC GENERATING CAPACITY BY FUEL — Summer



of customer-owned generation, and increasing construction costs.

In the Florida subregion, 4 new coal plants totaling 1,946 MW are currently under construction. These additions plus major unit power coal-by-wire purchases and increasing cogeneration capacity will defer the need to add more capacity for load growth or reliability purposes until after the review period. Even though the subregion is aggressively changing its fuel base from oil to coal, oil will still play a major role in Florida, with over 43 million barrels required in 1994.

In the TVA subregion, the addition of the Watts Bar and Bellefonte nuclear plants will add approximately 3,500 MW of new capacity in the review period. Additional capacity is also provided from TVA's currently planned conservation, load management, and rate programs. Southern will add approximately 7,671 MW of generating capacity during the review period and continue its off-system coal-by-wire sales.

Utilities of the VACAR subregion continue to reduce dependence on oil by conversions from oil to coal, or from distillate fuel to dual-fuel operation. Approximately 370 MW are scheduled for conversion from oil to coal by mid-1987. At the completion of this program, approximately 3,700 MW will have been converted from dependence on oil or distillates.

The installed generating capacity margins for SERC are projected to decrease from 25.3% in 1985 to 20.5% in 1994 but are considered adequate for the period. If a sustained demand growth higher than forecast occurs, resources could be marginal in some subregions in the late 1980's or early 1990's. Individual systems may then be faced with less than desirable capacity margins before new base load generation could be placed in service or mothballed capacity returned to service.

TRANSMISSION

During the 1985-1994 period, SERC systems are planning the addition of 1,284 miles of 500 kV and 2,224 miles of 230 kV transmission lines. The scheduled additions represent an 11.7% increase in 230 kV and a 20.3% increase of 500 kV transmission facilities.

In 1985, the Florida subregion completed the 500 kV transmission system consisting of two 500 kV lines along the Florida east coast from Georgia to the Miami area in south Florida. These lines allow the state to import as much as 3,200 MW.

The Southern subregion plans the addition of 552 miles of 500 kV transmission lines (39.3% increase) and 896 miles of 230 kV transmission lines (14.2% increase). These lines will significantly improve the reliability of the Southern system and allow an increase in the transfer capabilities with most adjacent regions and

subregions. An exception is the Southern-TVA interface which tends to show a decreasing transfer capability over the review period. Additional reviews of this interface capability will be made as appropriate.

New EHV transmission expansion in the TVA subregion during this assessment period is attributed primarily to changing flow patterns associated with the addition of four base-load nuclear units in the eastern portion of the system and to increased load growth primarily in the western portion of the system. During 1984, plans were formalized to construct the Maury 500 kV substation near Columbia, Tennessee by the summer of 1987. This substation, along with its associated transmission connections, will significantly increase bulk power reliability of the TVA system.

The VACAR subregion is planning the addition of 370 miles of 500 kV and 945 miles of 230 kV transmission. These additions represent a 23% increase in 500 kV and an 11% increase in 230 kV transmission.

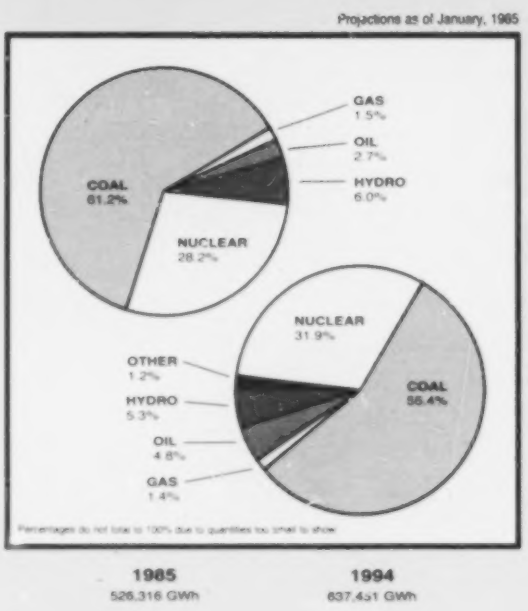
The planned SERC transmission additions will increase transfer capabilities within SERC and between SERC and other NERC regions. Even though the Region is projecting continued heavy economy transfers during the 10-year period, studies have shown that SERC reliability criteria will continue to be met.

OPERATIONS

Completion of the Duval-Poinsett 500 kV lines in November 1984 extended the interconnections from the Southern electric system to south Florida. These lines provide a greater margin of reliability and helped Florida to avoid any single-contingency separation from the Southern electric system during 1984. In an action designed to improve the state's response to a generation loss and enhance resynchronization should separation occur, the Florida Electric Power Coordinating Group, through its Operating Committee, has refined its underfrequency load shedding program. The Southern and Florida subregions have agreed to investigate transfer capabilities annually to provide guidance to their operators. As part of this effort, Florida has developed a system security model using 'real time' and static data. Southern will annually develop equivalents of the system outside the Florida subregion for the model and assist in the representation of 'real-world' operating conditions.

In the TVA subregion, recent DOE load reductions at the Paducah Plant near TVA's Shawnee Steam Plant have placed increased burdens on area transmission facilities. Under the current operating mode, loading on critical facilities can limit interregional transfer capabilities and/or area generation output. To allow full

SERC ELECTRIC GENERATION BY FUEL



generation at Shawnee during normal transmission conditions, relaying schemes have been installed to trip up to eight Shawnee units during a transmission contingency. New EHV reclosing schemes are being phased in on the TVA system in order to minimize the potential for shaft torque failures on large generating units connected to the 500 kV system and to increase stability margins by minimizing the effects of inadvertent tripping of unfaulted 500 kV lines.

The ability of the VACAR subregion to restore the system after a major disturbance was demonstrated in late March 1984, when the subregion experienced severe thunderstorms and tornados, causing the outage of fifteen 115 or 230 kV transmission lines. Most of the 530 MW of lost load was restored within a 12-hour period. Hurricane Diana struck the same general area in mid-September. All interrupted service was restored within 2 days. Neither of these occurrences caused system stability problems or resulted in disruptions outside the immediate area.

MAJOR REGIONAL ISSUES

Effect of Economy Transactions on Reliability. The transmission network is being called upon to transfer large amounts of economy interchange and coal-by-wire imports. The extended use of the transmission system can have adverse impacts upon the systems involved as well as upon third-party systems. These impacts are related to area voltages, line loadings, and

reactive reserves. While significant additional transmission has been added to the networks, the system must be continuously monitored to insure safe reliable operation.

Studies are routinely made to identify potential network problems associated with these transfers prior to seasonal peak conditions, and as a result, reliability problems have not occurred. Additional studies are now being made to identify potential problems during shoulder peak conditions when the likelihood for multi-party transactions may be the greatest. Adequate assessment of the subject transactions indicates the need for continued enhancement of communications between planning and operations personnel and joint participation in system studies.

Unit Aging. Preventive maintenance has historically kept the outage rate of units reasonably consistent throughout their useful lives. There is some concern within the Region over the long-term economic and reliability effects of significantly extending the useful life of generating units. Utilities, however, are seriously considering and beginning to make commitments to unit life extension programs. These programs, if properly implemented, are expected to be a viable economic alternative which can extend the life of a unit a number of years, thereby postponing new units with their high capital cost.

Southern has developed a method to economically evaluate life extension of the older units on the system. This life extension method consists of four phases: (1) major equipment economic screening, (2) major equipment inspection and testing, (3) balance-of-plant evaluation and total plant economics, and (4) program implementation. Phase 2 utilizes the services of the equipment manufacturer for inspection and testing to identify remaining life in the equipment and necessary changes and modifications to extend the life. The result of Phases 1-3 is a benefit/cost ratio for life extension.

Recent experience with generating unit reliability improvement programs within SERC has indicated that significant improvements can be made to increase the availability of existing capacity. Enhancements to existing units which will prolong the life of these units will continue to be made where economically justified.

Load Restoration Preparedness. The Florida subregion, through the FCG Operating Committee, has established specific procedures to restore load in the event of state-wide or individual system disturbances. In addition, during state-wide disturbances, a "state coordinator" is commissioned to administer FCG operating policies regarding operating reserve requirements of the FCG system. Schedules will be monitored within peninsular Florida and with other interconnected systems, ensuring prompt resynchronization when peninsular Florida experiences underfrequency conditions.

The Power Coordinating Center of the Southern electric system has the responsibility of coordinating the Southern resources to fulfill interconnected contractual agreements and supply territorial power requirements. If a widespread system disturbance occurs, each operating company effects the necessary steps to minimize the impact and coordinates with the control center to restore normal conditions. The center arranges for additional capacity and energy from neighboring systems as needed.

In the VACAR subregion, firm contract purchases are sometimes made from remote systems. Dealing with the remote system and all intervening systems can complicate an operator's problems of service restoration. It is recognized that from a system operations viewpoint, minimizing the duration of a service interruption is second in importance only to minimizing the frequency of service interruptions.

Mothballing Units. Mothballing is being utilized to retain, for future services, units which are not presently needed in an immediate status. Indications are that dry air is less costly than nitrogen as a preserving medium and can encourage more frequent inspections. In addition, dry air may provide more serviceable equipment when a return to duty is required.

In the last few years, some utilities have put a number of units into extended cold standby or extended cold shutdown. Measures are being taken to insure that these units can be brought back on line at a future date in the same condition as when they were taken off line. The opportunity to mothball units which are not presently needed for reliability provides significant economic savings.

TVA has adjusted the scheduled operation of 14 steam units for seasonal scheduling and mothballed 4 other units. The Watts Bar fossil units were mothballed in the spring of 1983 and can be restarted in approximately 30 days. The seasonally idled units are fully available during seasonal peak conditions. In addition, Florida has mothballed approximately 1,600 MW of capacity which is expected to be reactivated by the early 1990's.

The Southeastern Electric Reliability Council (SERC) includes 27 utility member systems located in 9 states in the Southeastern United States. SERC is divided into 4 subregions which are identified by the Florida peninsula (Florida), the geographical bounds of the Southern electric system (Southern), the geographical bounds of the Tennessee Valley Authority (TVA), and the Virginia-Carolinas area (VACAR).

SPP

1984 STATISTICS				
	Southeast	West Central	Northern	SPP
Summer Peak — MW	19,649	15,333	10,580	45,562
Winter Peak — MW	15,407	11,773	7,932	35,112
Annual Energy — GWh	107,049	72,014	46,579	225,642
Installed Capability (Summer) — MW	25,186	20,979	14,224	60,389

The adequacy of the Southwest Power Pool for the period 1985-1994 is satisfactory, based on present demand and energy forecasts, the schedule of new generating additions, and the addition of new transmission lines. Future availability of gas and oil fuels, the timely construction of the planned capacity additions and the ability to react to a major upsurge in the economy are factors that will influence the adequacy of power supply in SPP over the next ten years.

DEMAND AND ENERGY FORECAST

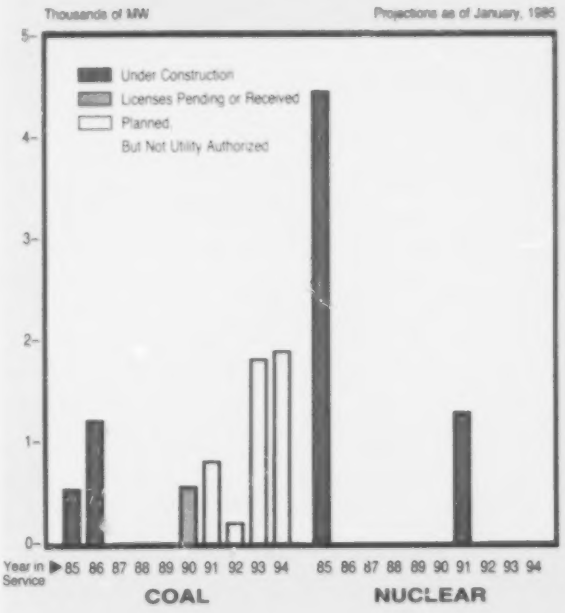
Demand and energy forecasts are prepared by the individual member systems of SPP. The 10-year forecasts of peak hour demand growth rates for each system range from 0.5% to 6.1% per year. The majority of the forecasts consider area economics along with the impact of price elasticity, conservation and other factors that will have an influence on the future use of electricity.

The SPP demand and energy forecast is a summation of the individual forecasts prepared by the member systems. For the 1985-1994 period, an average annual growth rate is projected to be 2.5% per year. This is a reduction from the 2.7% average annual rate projected last year. The corresponding energy forecast indicates a 2.6% average annual growth rate as compared to 3.0% projected in 1984.

GENERATION ADDITIONS

A total of almost 15,000 MW of generating capacity is scheduled to be installed during the 1985-1994 period. Approximately 7,400 MW of this new capacity is now under construction and is scheduled to be brought on line in 1985 and 1986. Of the remaining capacity additions between 1987 and 1994, nearly 6,600 MW is planned but not utility authorized, indicative of the caution existing within the industry today.

SPP MAJOR GENERATING UNIT ADDITIONS



In this time period, about 12,800 MW of the new generation will be base load capacity. Approximately 44% (5,661 MW) of the base load capacity will be nuclear while the remaining 7,132 MW will be coal or lignite-fired. Nearly 2,000 MW of peaking capacity,

principally combustion turbines, is also planned for this time period.

It should be noted that of the 13 coal/lignite units scheduled through 1994, 7 units totaling about 4,300 MW are only in the planning stage. The committing of these units to actual construction will depend not only upon future demand forecasts but also on the ability of the individual systems to finance the construction programs and to obtain the necessary regulatory approvals and licenses. Because of the long lead time required to plan, license and construct major generating units, the reliability of electric supply could be adversely affected in the 1990's if there is a significant increase in SPP's actual demand — or if units are postponed or canceled.

ADEQUACY OF POWER SUPPLY

The adequacy of SPP for the period 1985-1994 is satisfactory, based on present demand and energy forecasts, the schedule of new generating unit additions, and the addition of new transmission lines. However, there are two general areas of concern that could adversely affect SPP's future reliability. These are:

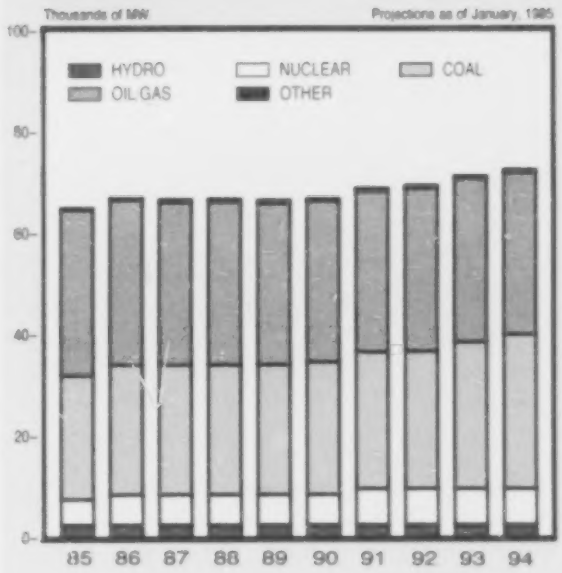
- Future availability of gas and oil fuels will continue to be a concern, especially in light of past experience.
- Ability to react to a major upsurge in the economy is also a concern. Because of the long lead time required to construct major generating units, a significant increase in demands above that now forecast could lead to a problem of adequacy in the 1990's.

Based on the current peak demand forecast and generating capacity addition schedule, the projected capacity margin of SPP for the 1985-1994 summer periods will decline from 27.8% to 17.8%, based on resources. Present projections show that SPP will require approximately 786 billion cubic feet of gas and approximately 8 million barrels of oil to generate its energy requirements in 1994. Combined, this represents the equivalent of 135 million barrels of oil, approximately 28% of SPP's total energy generation in 1994.

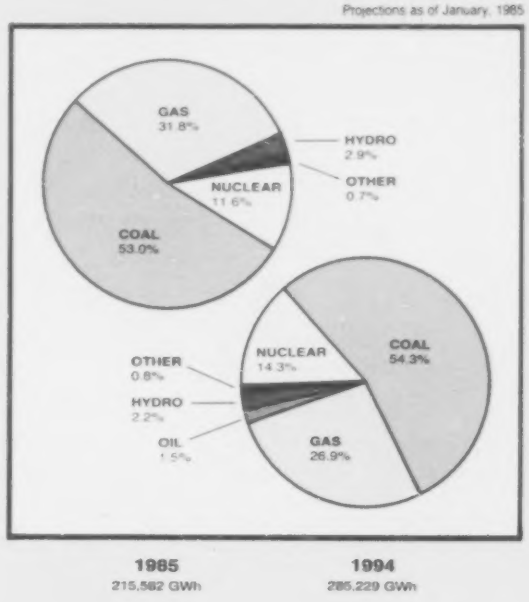
TRANSMISSION

Throughout the years of interconnected operations, the bulk transmission network has proven to be an indispensable asset for the reliability of electric service. During the 1985-1994 time period, the SPP member systems plan to install approximately 587 miles of

SPP GENERATING CAPACITY BY FUEL — Summer



SPP ELECTRIC GENERATION BY FUEL



500 kV, 1,206 miles of 345 kV, and 1,346 miles of 230 kV transmission lines. Major 500 kV additions will be built in the states of Louisiana, Mississippi, and Arkansas along with construction of major 345 kV additions in the states of Oklahoma, Kansas, Missouri and Texas. Another 500 kV SPP-SERC interregional tie is planned to the Tennessee Valley Authority.

Three HVDC ties to adjoining regions have recently been completed and placed in service. Two of these ties are with systems in WSCC and provide a combined transfer capability of 440 MW initially, with an ultimate capability of 880 MW. The third tie is with ERCOT providing transfer capability of 200 MW.

Systems are continually reviewing the reliability of the existing transmission network, as well as the reliability of the planned transmission network. Part of this review includes the running and analyzing of regional studies. Current studies which are conducted by representatives of the member systems indicate that existing facilities, along with those planned for the next ten years, will provide SPP with a reliable transmission network. However, increasing economy energy transfers to reduce the cost to the customer are placing an ever-increasing load on the bulk transmission network. This should be brought to the forefront when stressing the importance of the existing bulk transmission network and its timely expansion.

OPERATIONS

Large transfers of energy are now a routine occurrence and have complicated utility operations within SPP. To maintain a high degree of service reliability, it is absolutely essential that control centers have knowledge of conditions within other control areas. In SPP, this is accomplished on a daily basis through the SPP computer facilities. Information on generation and transmission outages, both planned and forced, are routinely shared with the members of SPP. Control centers continue to be upgraded and operator training continues to further enhance their knowledge and abilities.

The Southwest Power Pool (SPP) includes 38 power suppliers serving customers in the states of Kansas, Oklahoma, Missouri, Arkansas, Mississippi, Louisiana, Texas and New Mexico. The membership is composed of 11 municipals, 1 state agency, 6 cooperatives, 19 investor-owned utilities and 1 Federal agency.

WSCC

1984 STATISTICS			
	Northwest Power Pool U.S.	Canada	Rocky Mountain
Summer Peak — MW	25,384	9,103	5,608
Winter Peak — MW	34,043	11,583	5,794
Annual Energy — GWh	183,986	66,929	33,088
Installed Capability (Summer) — MW	46,628	17,271	8,807
	Arizona-New Mexico	**California-Southern Nevada**	**Total WSCC — U.S.***
Summer Peak — MW	9,384	40,933	80,048
Winter Peak — MW	7,844	31,321	77,579
Annual Energy — GWh	46,695	205,168	468,937
Installed Capability (Summer) — MW	11,999	47,309	114,854

*Since the subregional peak demands may occur in different months than the coincident total WSCC-U.S. peak demand, the sum of the individual subregional values may not always equal the WSCC-U.S. total.

The WSCC Region continues to experience heavy economy energy transfers and to depend upon complex remedial action schemes to compensate for the lack of transmission. The transmission network is being strengthened during the next five years, but the transfers are expected to increase proportionally. The existing remedial action schemes are being reevaluated, upgraded, and expanded in an effort to reduce the frequency and impact of disturbances.

PEAK DEMAND AND ENERGY

The accompanying tables provide a comparison of this year's forecast of peak demand and energy with last year's forecast and summarize the 1984 peak demand and energy experience.

WSCC (U.S. and CANADA)
Comparison of Forecasts

	This Year's Forecast	Last Year's Forecast
10-Year Forecasts:		
Summer Peak Demand Growth Rate (%/yr)	2.4	2.7
Annual Energy: Growth Rate (%/yr)	2.5	2.9
Forecasts for Year 1993:		
Summer Peak Demand — MW	109,697	109,311
% Change	0.4	
Annual Energy — GWh (Median Hydro)	663,420	666,278
% Change	-0.4	

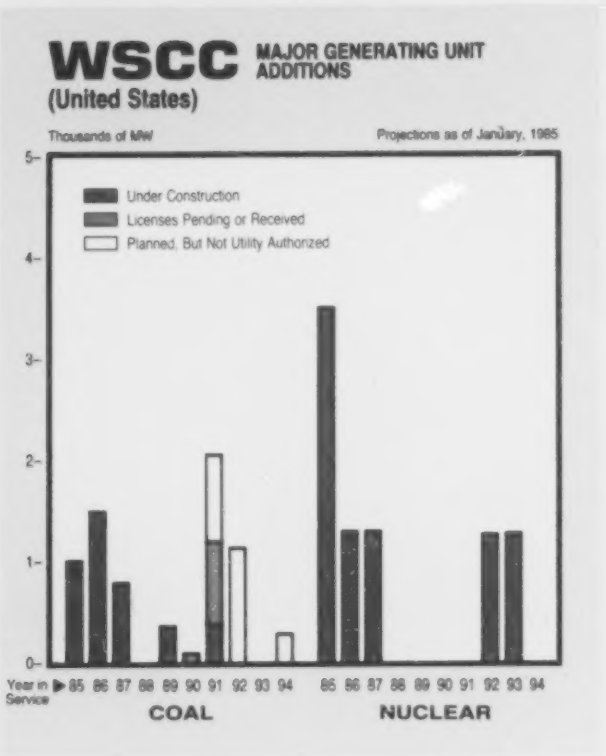
WSCC (U.S. and CANADA)
1984 Peak Demand and Energy Experience

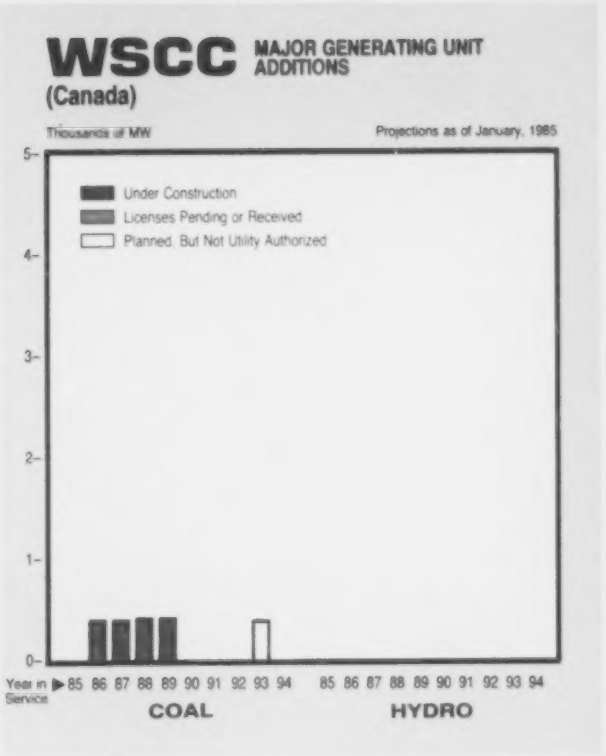
	Change vs 1983 Actual (%)	Change vs 1984 Forecast (%)
Summer Peak Demand	5.6	3.5
December Peak Demand	0.3	6.9
Annual Energy	7.4	3.8

GENERATING CAPACITY AND ENERGY SUPPLY

Generating capacity additions for the 1985-1994 period continue to reflect a reliance on coal and nuclear units. No new major hydro resources are planned through the end of the 10-year period.

Net coal-fired generating capacity additions, (8,899 MW) represent 38% of the planned net generating capacity additions for the WSCC Region during the next 10 years while net nuclear capacity additions (7,740 MW) account for 33% of total additions. Cogeneration planned during the next 10 years (2,641 MW) represent





11% of the total generating capacity additions and a 70% increase over the planned cogeneration additions (1,556 MW) reported for the 1984-1993 period.

There have been several deferrals and cancellations of generating units which were reported in the resource plans of one year ago. For the most part, the reduction in planned generation additions is due to the adequate capacity margins which are projected over the next 10 years. Through 1994, installed capacity margins range from 24% to 29%. These capacity margins will enable WSCC to respond to additional growth above the forecast in the event of an accelerated economic recovery.

Currently, 10,385 MW of the total 23,400 MW net capacity additions planned to be operational in 1994 are not yet under construction. If this capacity is not built, the Region will have reduced ability to respond to increases in demand in the 1990's; however, capacity margins would still be adequate through the next 10 years as long as loads do not increase faster than currently projected.

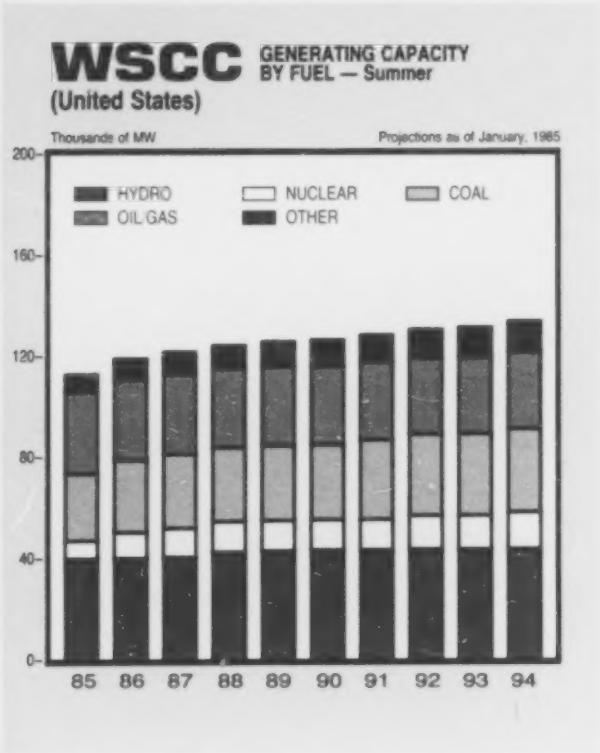
TRANSMISSION ADEQUACY/OPERATIONS

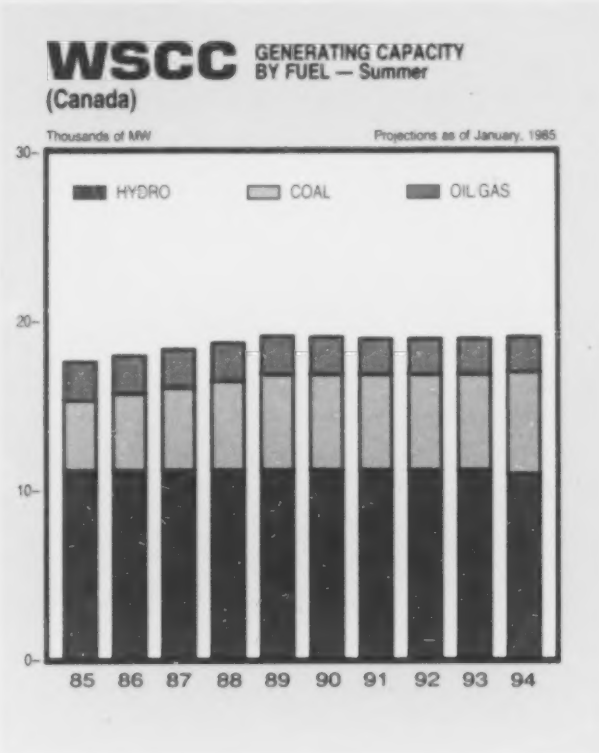
The WSCC interconnected transmission system is expected to be generally adequate to accommodate anticipated firm and most economy energy schedules during the 10-year period (1985-1994).

An issue of major concern throughout WSCC is the effect of economy transfers on bulk power system reliability. The Region's diverse load and resource mix, combined with localized surpluses of base load capacity, large fuel price differentials, and a trend toward more efficient operation on a regional scale, make surplus energy transfers between subregions an economic necessity for buyers and sellers alike.

Because of these increased economy energy transfers, the transmission system is being loaded to higher levels for sustained periods of time. Thus, the bulk transmission system is being operated to provide greater economic advantages even though this mode of operation poses greater risks to system reliability.

Interarea power transfer levels have been increased primarily through the implementation of an evolving and increasingly complex network of monitoring, signaling, relaying and switching logic systems referred to as remedial action schemes. As a result, in the absence of significant transmission additions, the reserve capacity in the transmission system has been reduced. At these high transfer levels, system operators must constantly factor several operating constraints into their decision making. As an example, the maximum allowable transfer from the Northwest to California on the ac





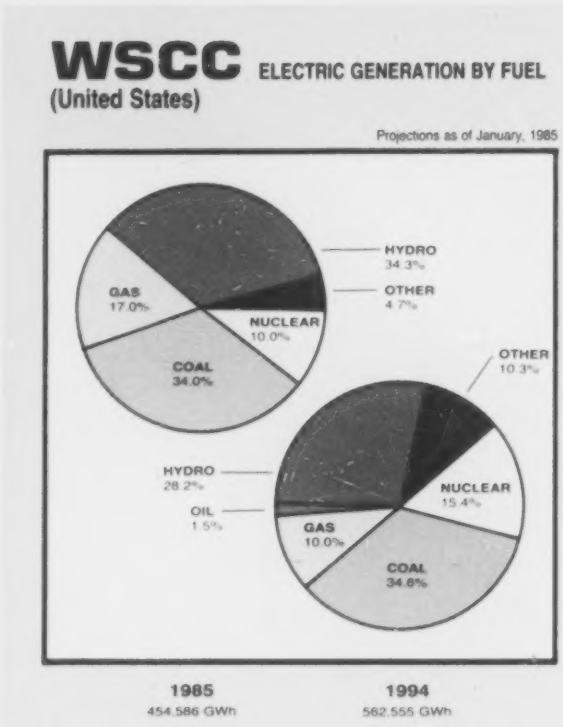
Pacific Intertie depends upon several other system conditions including the power flow from Arizona to California and the power flow from Utah/Colorado to Arizona/New Mexico.

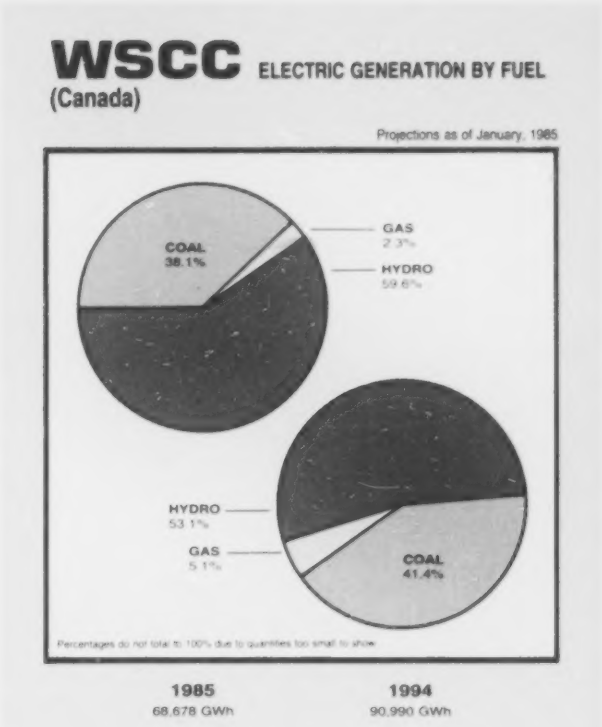
WSCC has recently experienced reliability problems associated with its remedial action schemes. During 1984, two ac Pacific Intertie disturbances occurred in which the remedial action scheme failed to operate properly, and one dc Pacific Intertie disturbance occurred in which the designed remedial action scheme was inadequate. Though there is currently no specific criteria for remedial action failure, these disturbances have resulted in loss of load outside the disturbance area, and are considered unacceptable by the affected utilities.

WSCC is making a concerted effort to improve existing remedial action scheme and provide for the development of more reliable schemes in the future. Special work groups and task forces have been organized to deal with these problems and a great deal of effort is being expended to reasonably assure an acceptable level of reliability. In particular, utilities associated with the ac and dc Pacific Interties have begun to initiate reliability improvements on a broad front. Improvements being considered to reduce the incidence of Intertie outages include replacing protective relaying, use of single pole switching and shortening of maintenance intervals and repair time. Modernization of the remedial action schemes is planned to improve control action reliability when ac or dc Intertie outages occur.

During the 1985-1990 time frame, several key transmission related projects are likely to have a significant impact on the operation of the WSCC interconnected system. These projects include:

1. Upgrading the transfer capability of the Celilo-Sylmar dc line from 1,600 MW to 2,000 MW — 1985.
2. Upgrading the transfer capability of the Northwest to California ac Pacific Intertie from 2,800 MW to 3,200 MW — 1986.
3. Completion of the 1,520 MW Intermountain Power Project generating plant and dc line to California — 1986-87.
4. Upgrading the Celilo-Sylmar dc line from 2,000 MW to 3,100 MW — 1988-89.
5. Completion of the third Northwest to California ac Pacific Intertie — 1989-90.
6. Increasing the Arizona-California transfer capability from 4,300 MW to 4,650 MW in 1985 and to 5,200 MW in 1987.





The Council has placed a high priority on studying the impact of these projects on the reliability of the WSCC interconnected system and evaluating alternative remedial action schemes which will confine the effects of disturbances involving these projects to the project participants and minimize the impact on neighboring systems.

COGENERATION AND ALTERNATIVE RESOURCES

The California-Southern Nevada Power Area and the Northwest Power Pool Area are the two areas projecting the most growth in cogeneration and alternative resources. Cogeneration is projected to increase 300 percent (623 MW to 2,527 MW) in the California-Southern Nevada Power Area over the next ten years. Cogeneration additions are also projected in the Northwest Power Pool and the Rocky Mountain Power Areas. This growth is stimulated by state regulatory commissions' interpretation of the Public Utilities Regulatory Policies Act. Several state commissions, most notably California and Idaho, have stressed the importance of these alternative resources and have specified "avoided costs" at levels that ensure resource development. In the Northwest Power Pool Area, the Northwest Power Planning Council has also emphasized the need to rely on alternative resources, in conjunction with a major conservation program.

Although non-utility-owned generation has not yet grown to major proportions in the WSCC Region, utilities are concerned about the availability of some of these resources in future years should tax incentives be reduced or removed. Additional concerns include:

1. Utilities have no control or authority regarding the dispatch of cogeneration.
2. Cogeneration units frequently become inoperative during system emergencies.
3. Transmission overloading may result in some areas because of added generation connected to the system.
4. Utilities may be required to accept proposals for cogeneration additions from qualified applicants even though adequate resources are already available.

A uniform interpretation of PURPA by state regulatory commissions would be very beneficial in establishing uniform policies concerning reserves, metering, control, etc.

Economic incentives will make utilities more competitive in obtaining access to and acquiring lowest cost resources to serve their customer at the lowest possible rates. Commitments to marginally or non-cost-

effective generation and transmission projects could prove to be financially disastrous. The resource planning and acquisition process will require a great deal of study and continued effort if utilities are to maintain financial health.

NORTHWEST POWER POOL AREA

The Northwest Power Pool Area is composed of the states of Washington, Oregon, Idaho, Western Montana, Utah, Northern Nevada, small portions of Wyoming and California and the Canadian provinces of British Columbia and Alberta.

Projections of peak demand and energy requirements for the 1985-1994 period indicate a further reduction from last year's 10-year forecasts. The projections are shown in the accompanying table. Winter generating capacity margins range between 19% and 25% for the next 10 years, even though several large generating units have either been delayed, canceled or rescheduled beyond the end of the 10-year period. In addition, studies are currently being conducted to determine the destiny of partially-completed and mothballed nuclear plants WNP1 and WNP3. These units have been rescheduled for 1992 and 1993, but they could be delayed further or canceled if load forecasts continue to decline.

Northwest Power Pool (U.S.)
Comparison of Forecasts

	This Year's Forecast		Last Year's Forecast
10-Year Forecasts:			
Summer Peak Demand Growth Rate (%/yr)	1.7		2.2
Annual Energy Growth Rate (%/yr)	1.9		2.5
Forecasts for Year 1993:			
Summer Peak Demand — MW	28,817		29,267
% Change		-1.5	
Annual Energy — GWh	215,736		224,930
% Change		-4.1	

Northwest Power Pool (Canada)
Comparison of Forecasts

	This Year's Forecast		Last Year's Forecast
10-Year Forecasts:			
Summer Peak Demand Growth Rate (%/yr)	2.8		3.7
Annual Energy Growth Rate (%/yr)	3.1		3.8
Forecasts for Year 1993:			
Summer Peak Demand — MW	11,861		13,040
% Change		-9.0	
Annual Energy — GWh	88,520		95,337
% Change		-7.2	

The past year has seen little change in the Area's transmission system. The two 500 kV Garrison-Taft lines are scheduled to be in service in October 1985. They will relieve a current transmission limitation in Western Montana that is at times limiting the output of the 1,360 MW Colstrip generating plant.

The 700 MW Colstrip Unit No. 4 has been delayed until April 1986. All limitations on the output of Colstrip will not be overcome until the Taft-Bell 500 kV line is completed in 1987, strengthening the interconnection between Montana and the Pacific Northwest.

The second ac-dc-ac tie between WSCC and MAPP was energized early in 1985. The tie is located in Eastern Montana and increases the transfer capability between WSCC and MAPP by 200 MW in both directions.

The upgrading of the ac and dc Pacific Interties during the 1985-90 time period is intended to take advantage of additional power that is expected to be available for export because of reduced load forecasts in the NWPP Area. It is economically advantageous to maximize operation of WSCC's lower cost resources by generating from hydro and low-cost thermal resources in the NWPP Area to replace more costly gas- and oil-fired generation in the California-Southern Nevada Power Area. The total planned capability of the ac and dc Pacific Interties by 1990 is 7,900 MW, an increase of 3,100 MW. Recent studies have indicated that an outage of the Celilo-Sylmar dc line, while operating at its new upgraded rating, could result in unstable system performance under certain system conditions. Studies

have been conducted to establish simultaneous transfer capability limits from the Pacific Northwest to California on the dc line and from Wyoming and Montana to the Pacific Northwest. Limitations from Wyoming and Montana to the Pacific Northwest are expected to end after completion of the Garrison-Taft 500 kV line.

In Alberta, several mine mouth coal-fired plants are under construction. However, two unidentified thermal plants previously planned for 1992 and 1993 have been delayed beyond the end of the 10-year period. There is some evidence that Canada's load growth is also slowing. British Columbia Hydro has no additional generation scheduled during the 10-year period, but will rely on existing hydro resources to serve its load. Surplus energy will be available for export during the 10-year period.

Cogeneration is a concern in Idaho. The rates, mandated by the Utility Commission, that utilities have been required to pay for cogeneration have resulted in amounts of existing and proposed cogeneration that now substantially exceed both present requirements and future requirements for many years. A rate increase to utility load customers has been required to pay for cogeneration. Proceedings are now before the Utility Commission to reduce the cogeneration rate and a partial temporary reduction has been granted.

ROCKY MOUNTAIN POWER AREA

The Rocky Mountain Power Area (RMPA) consists of Colorado, Eastern Wyoming and a small part of South Dakota. The accompanying table shows this year's forecast of peak demand and energy as compared to last year's. Summer generating capacity margins range between 18% and 29% for the next 10 years.

Rocky Mountain Power Area
Comparison of Forecasts

	This Year's Forecast		Last Year's Forecast
10-Year Forecasts:			
Summer Peak Demand Growth Rate (%/yr)	3.4		3.7
Annual Energy Growth Rate (%/yr)	3.7		3.7
Forecasts for Year 1993:			
Summer Peak Demand — MW	8,086		8,205
% Change		-1.5	
Annual Energy — GWh	47,679		47,166
% Change		1.1	

During 1984, two new coal-fired generation additions, Craig No. 3 (400 MW) and Rawhide No. 1 (250 MW) were placed in service. However, significant transmission enhancements have not yet been able to be made to improve the Area's power transfer capability to and from adjacent Areas, due to delays caused by the regulatory process.

The Rifle-San Juan 345 kV transmission line from Western Colorado to Northern New Mexico, originally scheduled for 1985, has now entered the construction phase. Completion of this line will significantly strengthen the existing Colorado to Arizona-New Mexico transmission system. Until completion of the line in 1986, the Area's transmission system will continue to be heavily loaded at times as a result of economy energy transfers, high levels of circulating power flow and service to loads in Southwestern Colorado. The present high levels of power transfer have the potential to jeopardize system reliability and restrict reserve sharing. The capability to schedule significant amounts of surplus energy to the southwest to displace gas- and oil-fired generation is severely limited during periods of high circulating power flow. Area utilities are maintaining close coordination at both operating and planning levels to assure that transfer capability limits are not exceeded.

A significant system development for the RMPA is the third ac-dc-ac tie between WSCC and MAPP. The tie, located in Southwestern Nebraska, is under construction and will increase the transfer capability between WSCC and MAPP by 200 MW in both directions. The tie is scheduled for completion in 1987.

ARIZONA-NEW MEXICO POWER AREA

The Arizona-New Mexico Power Area consists of Arizona, most of New Mexico and the western-most part of Texas. The accompanying table shows this year's forecast of peak demand and energy as compared to last year's. Summer generating capacity margins range between 22% and 31% for the next 10 years.

Arizona-New Mexico Power Area
Comparison of Forecasts

	This Year's Forecast		Last Year's Forecast
10-Year Forecasts:			
Summer Peak Demand Growth Rate (%/yr)	4.0		4.4
Annual Energy Growth Rate (%/yr)	4.3		4.8
Forecasts for Year 1993:			
Summer Peak Demand — MW	13,909		13,964
% Change		-0.4	
Annual Energy — GWh	66,373		69,429
% Change		-4.4	

The 210 MW coal-fired PEGS Unit No. 1 was placed in service during 1984. Projected net generating capability additions for the 1985-1994 period total approximately 7,000 MW and are predominantly coal-fired and nuclear units. A total of 1,560 MW of hydro generating capability additions are reflected in the Area's total generating resources when the U.S. Bureau of Reclamation assumes operation of Hoover hydro units from several California Area utilities in 1987. Four oil-fired units at one plant on the Tucson Electric Power system are being converted to burn coal in a three-stage project beginning in 1986. (This reduces the capability of this plant from 420 MW to 260 MW.)

Construction of the three-unit 3,810 MW Palo Verde nuclear plant located in Southwestern Arizona is progressing steadily. The 1,270 MW Palo Verde Unit No. 1 unit is scheduled for commercial operation in late 1985. The remaining two 1,270 MW units are expected to be in commercial operation by the second or third quarter of 1986 and 1987, respectively.

The Arizona-New Mexico Area's share of the Palo Verde nuclear plant represents approximately 40% of the Area's planned net generating capacity additions over the next 10-year period. The Area participants are concerned that regulatory restrictions may cause licensing delays or result in reduced permissible unit output; either of which has the potential to adversely impact the reliability and adequacy of power supply within the Area.

Financial strength continues to be a major issue within the Arizona-New Mexico Power Area. Utilities within the Area project an increasing need to sell surplus power during off-peak periods to neighboring areas as a means of relieving financial stress. Other methods include block energy sales outside the Area or sale of ownership in surplus capacity. Subsidiary companies have been formed or are being evaluated as a means of shielding a parent company from the financial burdens of constructing new generating facilities.

CALIFORNIA-SOUTHERN NEVADA POWER AREA

The California-Southern Nevada Power Area consists of California and Southern Nevada. The accompanying table shows this year's forecast of peak demand and energy as compared to last year's. Summer generating capacity margins range between 19% to 25% for the next 10 years.

California-Southern Nevada
Power Area
Comparison of Forecasts

	This Year's Forecast		Last Year's Forecast
10-Year Forecasts:			
Summer Peak Demand Growth Rate (%/yr)	2.1		1.9
Annual Energy Growth Rate (%/yr)	2.1		2.2
Forecasts for Year 1993:			
Summer Peak Demand — MW	47,363		45,608
% Change		3.8	
Annual Energy — GWh	245,112		229,416
% Change		6.8	

In 1984, the California-Southern Nevada Power Area added two major resources, the 1,172 MW Helms Pumped Storage Project and the 1,100 MW San Onofre Nuclear Unit No. 3. Also of significance was the return to service of the 436 MW San Onofre Nuclear Unit No. 1 which had been off-line since February 1982 for seismic upgrades.

The 278-mile Palo Verde-Miguel 500 kV transmission line went into service in June, reinforcing the interconnection between the California-Southern Nevada Power Area and the Arizona-New Mexico Power Area. This line increased the total transfer capability by 700 MW (from 3,600 MW to 4,300 MW). Also, after nearly 4 years of application processing, the California Public Utilities Commission licensed the 80-mile Devers-Valley-Serrano 500 kV transmission line which, when completed in 1986, will provide additional

support between the California-Southern Nevada Power Area and the Arizona-New Mexico Power Area.

In 1985, the overall outlook is for an adequate bulk power network with continued high levels of economy energy transfers. The Pacific Northwest-Southwest (Celilo-Sylmar) HVDC Intertie was upgraded from 1,600 to 2,000 MW early in 1985, and the Diablo Canyon Nuclear Unit No. 1 was placed in commercial operation in May 1985.

Over the next ten years, the California-Southern Nevada Power Area will face several significant issues. The rate treatment of new generation and transmission facilities by Public Utility Commissions could adversely affect utility project investment strategies. If the only projects allowed in rate bases are those which benefit current ratepayers, utilities will be reluctant to invest in beneficial long-range projects where near-term ratepayer benefit is uncertain.

Western Systems Coordinating Council encompasses approximately 1.8 million square miles of territory in 14 western states plus parts of 2 Canadian provinces. The Region is characterized by extremes in population and load densities in addition to long distances between load centers and power generation sources. The Region is subdivided into 4 areas, namely: the Northwest Power Pool Area, which is winter peaking and heavily dependent on hydro generation; the Rocky Mountain Power Area, which is either summer or winter peaking with a 28% hydro and 60% coal-fired generation mix; the Arizona-New Mexico Power Area, which is summer peaking with a 37% gas/oil and 57% coal-fired generation mix; and the California-Southern Nevada Power Area, which is summer peaking and heavily dependent on gas- and oil-fired generation.

INTERREGIONAL REVIEW SUBCOMMITTEE

WAYNE R. SCHMUS, Subcommittee Chairman
Chief Planning Engineer-Transmission
SOUTHERN CALIFORNIA EDISON COMPANY

EUGENE H. KAISER
Director of Power Resources and System Planning
CONSUMERS POWER COMPANY

ROY R. PARKS
Manager, Generation/Fuel Planning
TEXAS UTILITIES GENERATING COMPANY

H. THOMAS MILBOURNE, JR.
Manager-System Planning
DELMARVA POWER & LIGHT COMPANY

JOHN B. PRINCE, JR.
Manager of System Planning
WISCONSIN ELECTRIC POWER COMPANY

GERALD J. KRAUSE
Division Manager, System Planning
OMAHA PUBLIC POWER DISTRICT

GEORGE C. LOEHR
Engineering Manager
NORTHEAST POWER COORDINATING COUNCIL

JAMES E. SCALF
Director, System Planning
FLORIDA POWER & LIGHT COMPANY

MARION M. RIGGS
Director, Planning Services
ARKANSAS POWER & LIGHT COMPANY

WILLIAM R. BOSSHART
Director
NORTHWEST POWER POOL COORDINATING GROUP

A. JAMES HARRIS
Manager-Resource Utilization
ONTARIO HYDRO

JOE E. BURRIS
Senior Consultant
TAMPA ELECTRIC COMPANY

TOM KENNEDY
General Manager System Operations
UNION ELECTRIC COMPANY

HARRY W. COLBORN
Director-Engineering
NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL